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# Contracts-for-Difference to support renewable energy technologies: Considerations for design and implementation

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Vasilios Anatolitis, Corinna Klessmann

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# Contracts-for-Difference to support renewable energy technologies: Considerations for design and implementation

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## Executive Summary

In this work, we present the major application and impact areas of Contracts-for-Difference (CfDs) in a European context, describe the most relevant design dimensions and discuss several design packages for CfDs as combinations of distinct design choices. We discuss these separately and in comparison. We also provide a detailed overview of CfD schemes implemented in Europe.

This work comes against the backdrop of an ongoing European debate on reforming the electricity market and the broader introduction of CfDs. Leading voices in academia, the EU and its Member States agree that electricity markets must be supplemented with additional long-term options, including CfDs. Different experts advocate for different versions and implementation options of CfDs, including generation-based and generation-independent design approaches. Unfortunately, the already existing breadth and variety of design options for CfDs are not always acknowledged and hence comparisons and assessments have so far only been made on a partial foundation.

A key design question for renewable support schemes in general, and CfDs in particular, is how to prevent electricity market distortions and preserve short-term, operational market integration without jeopardising the effectiveness of the schemes in leveraging investment of private capital for renewable energy deployment. We show in this report that a number of different CfD designs have already been developed aiming at preserving dispatch efficiencies and are, in fact, already implemented in various European countries. We describe how generation-based CfDs can be non-distortive for day-ahead markets based on existing designs. We discuss remaining issues that mainly arise through spill-over incentive effects across market segments (e.g. towards intraday, balancing and futures markets). We also discuss generation-independent CfDs, which have theoretical advantages over generation-based designs, in particular in relation to intraday and balancing markets, but feature unresolved implementation challenges and would imply rather significant changes in the market.

We find that every CfD implementation faces numerous design choices, which all come with their own challenges and trade-offs. The answers to many CfD design questions will be highly context-specific, and evaluations for different CfD design choices must take into account the idiosyncrasies of each specific environment and market situation.

With this report, we strive to contribute to an objective debate in which all stakeholders can engage in an unbiased discussion of pros and cons, strengths and weaknesses of all CfD design options, to find the best solution for each country and market situation. We strive for this report to become a comprehensive reference that provides overview and discussion of impact areas, design dimensions and choices for different CfD types. This report shall give opportunity for an informed basis for discussion of CfD designs supporting the European leap towards CfDs as a major mechanism for the support of renewable energy.

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# 1 Introduction

Boosting the deployment of renewable energy (RE) in the European electricity system is one key component of the EU's legislative Fit-for-55 package, which provides a framework to reach the EU's target to reduce emissions by at least 55% by 2030. Accordingly, the renewable energy directive (REDII) planned to increase the renewables target from 32% to 40% by 2030. As a result of the energy crisis, targets for 2030 have been further increased to 42.5% (with a potential top-up to 45%) in the revised Renewable Energy Directive (REDIII) that has been adopted in 2023. This ambition requires strengthened framework conditions that are able to leverage private capital for RE investments. These framework conditions include market design on the one hand and the use of support schemes on the other. At the same time, the recent energy crisis has shown that European electricity prices can be driven to unsustainably high levels through increasing fossil fuel prices. Currently, market instruments to protect consumers against these price hikes and producers against general volatility are limited, as forward markets lack availability and liquidity (ACER, 2023). As a response to the need of increasing the RE share while maintaining electricity costs at an acceptable level for consumers, the European Commission (EC) has been working on a speedy reform of the European electricity market, leading to a provisional agreement between the EC, the European Parliament and the Council on 14 Dec 2023 (EU Council, 2023).

The agreement stipulates that support for RE technologies (and nuclear energy) shall be in the form of two-sided Contracts for Difference (CfDs) or equivalent schemes (with the same effect as CfDs) for new investments and for repowering, capacity expansion or lifetime extension of existing installations. Revenues from CfDs shall be redistributed to final customers or may be used to “finance the costs of the direct price support schemes or investments to reduce electricity costs for final customers” (EU Council, 2023). To ensure legal certainty for ongoing projects, CfDs need only be implemented after a transitional period of three years after the regulation comes into force (i.e. from 2027), and after five years for offshore hybrid assets connected to two or more bidding zones.

The agreement between the EC, the European Parliament and the Council comes after a lively debate about the future role of CfDs in European electricity markets, which was initiated by the EC's proposal in March 2023 to designate CfDs as the preferred type of support for RE technologies. Currently, governments facilitate investment in renewables through a variety of different mechanisms, but CfDs have recently emerged as one of the essential instruments for large renewable energy projects (Renaud et al., 2023). Given the binding provisions of the electricity market reform and the many positive experiences using CfD in different European countries, we expect many Member States to start introducing CfDs for RE support.

Two-sided CfDs have so far been used in more than 200 auctions across ten European countries, namely Denmark, France, Greece, Hungary, Ireland, Italy, Poland, Portugal, Spain, and the United Kingdom (see also Table 1). CfDs are currently a largely European phenomenon, as they require liquid electricity markets. But also, some schemes in the US have similar characteristics. The use of CfDs increased over time. E.g., 2016 only saw about 13 auctions for CfDs, whereas the number grew to almost 50 in 2021 (Anatolitis & Jimeno, 2021). In recent years, CfDs were used in approximately half of all competitive support scheme allocation processes, according to data from the AURESII project (Anatolitis & Jimeno, 2021).

The ten European countries that use (two-sided) CfDs have implemented them in highly differentiated ways. No single implementation is like any other. Table 1 lists some major characteristics of each scheme in its most current implementation. A more detailed account about the history and development of CfDs in individual countries can be found in Appendix A.

CfDs were conceptualised for the UK in a White Paper (DECC, 2011), at the time termed 'two-way FiT CfD', in which reference was made to the existing implementation of a similar mechanism in Denmark (p. 39), where 'variable price premium' schemes have been applied in offshore wind auctions since 2005. Indeed, the UK CfD scheme is often referred to as the 'conventional CfD' (see, e.g. (Schlecht et al., 2024)). Price premium schemes have been used across Europe even before they were made obligatory for new RE support schemes in the 2014 'Energy and Environmental State Aid Guidelines' (EEAG) (EU Commission, 2014). Support mainly focused on payout, often without clawback clauses (making them one-sided schemes). Because of high strike prices and low electricity prices at the time, it was deemed highly unlikely that clawback could be expected to play a significant role, and one-sided and two-sided designs were not always accurately distinguished.

Until very recently, all existing CfD schemes in Europe were generation-based, i.e. they use the realised production of the individual plant as basis for payout and clawback calculations. Belgium has now implemented a generation-independent CfD in law, which has, however, until the date of writing of this report, not been auctioned yet (Elia Group, 2023). General observations of implemented CfD schemes include a trend towards longer referencing periods, especially in Northern and Central Europe. In addition, pausing payouts during (a certain number of consecutive hours of) negative prices has become standard, as also requested in the EEAG. First schemes have been updated to use limited clawback mechanisms in certain circumstances and discussions on implementing a corridor to separate strike prices for payout and clawback have been gaining traction under the recent energy crisis.

**Table 1: CfD schemes implemented in European countries**

| Country | Duration (Years) | Reference period | Referencing method | Other features |
|---|---|---|---|---|
| **DK** | 20 | Annual | Uniform | Limited clawback / net payment cap |
| **FR** | 20 | Monthly | Volume-weighted | Premium for curtailment during negative prices |
| **GR** | 20 | Monthly | Technology-specific | - |
| **HU** | up to 25 | Monthly | Technology-specific | - |
| **IE** | 20 | Hourly | n/a | Compensation for unrealised available energy |
| **IT** | up to 30 | Hourly | n/a | - |
| **PL** | 15 | Daily | Volume-weighted | - |
| **PO** | 15 | Hourly | n/a | - |
| **ES** | up to 20 | Hourly | n/a | Adjustment factor for remuneration at market price / Electricity market is regarded |
| **UK** | 15 | Hourly | n/a | - |

# 2 Functioning of Contracts-for-Difference

## 2.1 Basic principle

Contracts-for-Difference are widespread financial products with many applications. In this paper, we will focus on CfDs as a mechanism to support renewable energy investments by providing stable revenues during a substantial part of power plants' lifetimes. CfDs are often implemented in market-based long-term power contracts (such as power purchase agreements) and are now increasingly used in RE support schemes[1]. The determining factor is that in CfD contracts, payments are not made in exchange for physical delivery of power, but settled on financial basis, while producers sell their product on the regular market. Support payments are determined based on the difference between an agreed fixed strike price (usually established via competitive bidding) and a reference market price. If the reference market price is below the strike price, a payment will be made from the state (via a dedicated counterparty) to the producer (payout). If the reference market price is above the strike price, a payment will be made by the producer to the state (clawback). The net level of support paid per kWh is the difference between the strike price and the reference market price. Whereas in a one-sided CfD, the producer could keep revenues above the strike price, the two-sided CfD (the focus of this paper) introduces the pay-back obligation.

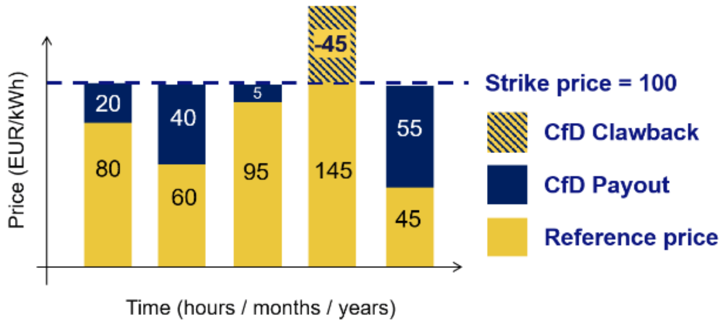


**Figure 1** Basic functioning of CfD payments

The exact definitions of strike price (or two strike prices in a cap-and floor scheme) and the calculation of (negative) support via the reference market price can vary greatly and are discussed in detail in the following chapters.

CfDs are particularly relevant for assets with high upfront capital needs. The high capital-intensity makes financing and cost of capital a crucial factor for investment. The (often fixed) payment obligations over long time periods stemming from financing, paired with a reliance on revenues from electricity markets that feature highly volatile prices, creates a situation in which support instruments that provide de-risking have great leverage and can enable investments that would have not been possible otherwise. Since long-term hedging options on electricity markets are limited, state interventions in form of long-term revenue stabilisation can be necessary for RE financing (Beiter et al., 2023). The symmetry of payments in CfD contracts ensures that protection against price volatility comes at the price of foregone opportunities to

[1] In this paper we focus on non-dispatchable RE, i.e. solar PV, wind onshore and wind offshore. For biomass, biogas and hydroelectric power generation, many of the considerations around CfDs change and we deem implementing CfDs for dispatchable RE as not recommendable. This is mainly the case because dispatch incentives are not efficient in this case.

benefit from very high market prices. CfDs essentially trade price protection for high profit opportunities. Consumers can benefit from the profits collected during periods of high prices. CfD can also induce overall cost reductions for the supported technologies, due to improved financing conditions and decreased cost of capital, through lower equity return requirements and a higher debt share (Đukan & Kitzing, 2021; Gohdes et al., 2022).

**CfDs as financial derivatives**

CfDs are very common financial derivative contracts. The largest markets for financial CfD products are currency exchange and interest rate swaps. CfDs are derivatives, as not the actual good is traded, but transactions are purely financial: One party who is exposed to variable prices (a ‘floating rate’), and who wishes to stabilise them, enters into a contract with another party who agrees to stabilise the prices for the first party (provide a ‘fixed rate’), by means of financial settlements. In practice, the net payment obligation between the parties is for each settlement period determined by the difference between the fixed and the floating rate. The CfD is a fixed-for-floating swap: the first party now experiences fixed prices, whereas the second party is financially exposed to future price changes. The CfD hedges the first party against exposure to variable prices.

## 2.2 Key impact areas of CfDs

CfDs are used to pursue different functions, either individually or in combination. We describe five key impact areas of CfDs, namely the closing of potential profitability gaps, capping (and collection) of revenues, enabling market integration, allocating risks, and addressing missing long-term markets. Depending on policy preferences, priorities for the different impact areas of CfDs may vary. There may also be interactions between the impact areas (see section 2.2.6).

### 2.2.1 Closing the profitability gap

For a RE project to be profitable, the income from producing and selling electricity, for instance at the power exchange, needs to at least match the total expenditure of a project (capital and operating expenses as well as costs of capital, i.e. required return of the investment). Whether there is any profitability gap for RE investments on the market and how large it is, can to some extent be measured by the relation between the Levelised Cost of Electricity (LCoE), i.e. the costs for each unit of produced electricity covering the overall lifetime of a plant, and the revenues for each unit of sold electricity. LCoE are not only influenced by the total project cost, but also by the expected output of a given plant, which is in turn dependent on the resource availability and site quality.

Revenues for RE projects are in Europe typically generated at the power exchange and the largest share is traded on the day ahead market. Revenues can be generated via bilateral contracts (e.g. so-called power-purchase-agreements), but also their pricing is typically oriented towards expected prices at the day ahead market. A defining factor for revenues is the capture price at which producers sell their energy. Capture prices for RE technologies tend to decrease with increasing RE shares: RE production tends to correlate positively within a bidding zone and the simultaneous RE production of a given technology decreases their value at times of infeed. This effect is also known as the “cannibalisation effect”. The cannibalisation effect can generally be reduced by increased flexibility options on markets (i.e. demand-side flexibility and storage), which leads to shifts in electricity consumption to times with high RE feed-in. The extent to which demand-side flexibility can offset the cannibalisation effect depends on the speed and volumes at which flexibility options can enter the market. In many EU electricity markets, RE deployment is quicker than the expansion of flexibility options, hence a bottom-line decrease in RE market values is among the likely scenarios.

Against this background, significant shares of RE projects in various electricity markets throughout Europe are faced with structural profitability gaps. A key functionality of CfDs is to close that profitability gap by means of providing support when market prices are consistently below the established strike price.

### 2.2.2 Capping of revenues and redistribution to end-consumers

In the wake of Russia's invasion of Ukraine in 2022 and the related European energy crisis, energy prices increased to unexpected levels, confronting consumers with significantly increasing energy costs and RE producers with unexpected income. The combination of additional end-consumer energy costs and unexpected income for producers sparked a debate over the functioning of electricity markets in Europe, resulting in various proposals on how to reform the electricity market as well as the EC proposal on the respective reform (EU Commission, 2023; Nabe & Staschus, 2023).[2] CfDs and their potential to skim/cap revenues have been assigned a central role in the EMD-reform in order to skim off windfall profits.

A core function of CfDs in the European EMD-reform agreement is the ability to cap revenues of producers and to create revenues for the state (i.e. skimming off revenues) at times when electricity prices are above the strike price. Establishing permanent revenue caps via CfDs (rather than implementing emergency measures for such revenue caps, as has been done during the crisis) can have two advantages. Firstly, it creates certainty for the market (which is crucial for investments in variable RE with higher upfront expenditures compared to dispatchable energy sources with fuel costs) and, secondly, it allows to introduce competition in relation to the capping mechanism and threshold, which can lead to more efficient market outcomes. The collected revenues can theoretically be used in various ways, but an option is to redistribute such income to electricity consumers to offset impacts of high electricity prices. This is also the suggested pathway in the European EMD-reform. How effectively revenues can be skimmed from producers in practice, depends on the design of the CfD, i.e. on the reference period as well as the definition of the strike price (see chapter 4).

### 2.2.3 Enabling market integration and fostering a cost-efficient system

When RE producers are facing productive risks, market integration can fundamentally increase system efficiency. By exposing RE projects to electricity market price signals, operators optimise their projects against short-, medium-, and long-term price signals. To the extent that market price signals comprehensively reflect various aspects of the electricity system, market price exposure creates incentives to behave in a way that is beneficial to the system.

Beneficial system behaviour means that producers produce in times of positive price signals from the different market segments and stop producing when prices are negative. Depending on the design of the CfD, price signals can be passed on or distorted. Distortions can lead to false incentives and inefficient behaviour by market players.

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[2] These proposals include, among others, the separation of the electricity market into one segment for renewables and one segment for conventional capacities, for example as part of the "Spanish" and the "Greek" proposals or the proposal for a "green power pool" (a CfD pool that is independent of the pricing on the wholesale market for certain consumer groups to ensure lower electricity prices) (Government of Greece, 2022; Government of Spain, 2023). A critical discussion is provided by (Meeus et al., 2022).

In contrast, if market price signals only reflect the power system characteristics to a limited extent, e.g. in the absence of local price signals, optimisation on project level can deviate from overall system efficiency. Where there are no price signals due to the absence or disruption of price signals (e.g. with regard to local network bottlenecks), additional coordination instruments and incentives can generate corresponding efficiency gains.

Variable RE power plants are less able to react flexibly to market price signals than dispatchable capacities. Nevertheless, there are short-, medium-, and long-term options for reacting to market prices, e.g. short-term curtailment of RE production at times of negative prices and medium-term optimisation of maintenance planning with respect to the dispatch. Price signals of up to one year can have an impact on the power plant design and site selection before the investment decision and should incentivise decisions that maximise market values and hence increase system benefits. This includes selecting locations promising higher market values and choosing plant design that maximises market values (e.g., “weak wind” systems, east-west orientation of PV systems, and combination with storage). Re-investment decisions including re-powering can also be incentivised. Such incentives can be controlled through CfD design, but there are also other options, such as dedicated measures, to cope with these issues.

### 2.2.4 Allocating risks

CfDs enable the core functions of closing the profitability gap, capping revenues and enabling market integration. These functions are always linked to allocating risks between RE producers and the state. For electricity markets to function efficiently, risks should be allocated so that RE producers are exposed to productive risks. Productive risks are those risks that investors, project developers and operators can calculate and properly mitigate. Unproductive risks are those that cannot be calculated and mitigated. Hence, RE producers should ideally be shielded from unproductive risks as those typically increase the cost of capital without making the allocation of capital and related investment decisions more efficient. For instance, project development risks and technology risks are deemed to be handled best by project developers. Risks that are (at least partially) unproductive, hence to be hedged by the CfD, include price risks, volume risks, basis risks as well as liquidity risks. The key question is what exactly constitutes productive and unproductive risks. This question is subject to controversial debate and has led to a range of different theoretical approaches, recommendations and practical policy design choices in CfDs across Europe.

**Price risk**

Price risk describes the risk of actual market price development deviating negatively from the price forecast, so that less revenue is generated than would be necessary, e.g. to repay debt. While there are also short-term price risks, the long-term market price risk is particularly difficult for investors to calculate, since the price development depends on many conditions, including the share and composition of renewable energy in the electricity system, the expansion of flexibilities, and available residual load capacities.

CfDs generally address price risk and stabilise prices for producers by means of paying the difference between a strike price and reference market price. The exact risk distribution depends on the definition of the reference market price, e.g. the timeframe and whether a technology-specific or technology-neutral reference price is established to calculate the support payments (see chapter 4). Price risk is closely linked to basis risk (see below).

**Volume risks**

Volume risks of renewable energy projects relate to deviations from the expected amount of electricity sold and/or support payment received. Naturally, the generation of electricity from wind and solar energy depends primarily on the weather conditions at the respective sites. The actual availability of renewable energy resources can only be forecasted to a certain extent and can deviate from the expected value in the short and medium term. Over longer periods of time (i.e. years and decades), however, production risks are greatly reduced.

Volume risks are also increasingly arising from temporary oversupply of renewable electricity. Oversupply can lead to negative prices, because of which operators cannot sell their electricity (if no support scheme is in place which (inefficiently) incentivises RE trade at negative prices). Mandated curtailment of RE production due to physical network constraints is generally dealt with in grid regulation and is not in scope here. (Voluntary) market-based curtailment of RE production due to negative market prices usually occurs at times in which plants have a particularly high generation potential, which amplifies the volume risk. The number of hours with negative prices depends, among other things, on the availability of demand-side flexibility and export capacities of a given bidding zone. In Europe, RE support is to an increasing extent paused during periods of negative prices (EU State Aid rules, EEAG). RE producers are therefore fully exposed to the 'lost' volume of supported production at times of negative market prices.

Depending on their design, CfDs can address the volume risk related to negative prices as well as to weather (see the section on generation-independent CfDs in section 4.3).

**Risks of deviating from a reference (basis risk)**

Deviation or basis risks are structural risks, which arise for operators of renewable energy sources when using support schemes with reference values or models. This includes using references prices (i.e. monthly or yearly reference prices) or reference electricity production volumes. The specification of the reference, which is independent of the specific market price and generation situation of the RE plant, creates a risk of deviation. A deviation from the reference does not necessarily have to come at a loss for the producer, it can also lead to additional income. Options for influencing the basis risk depend on the respective reference.

A CfD defines one or more references, e.g. a reference market price and/or a reference volume. The RE producer may negatively deviate from the reference market price by selling electricity at a lower value than the reference. During other times the producer may also outperform the reference price and generate higher revenues compared to the reference.

**Risk of financial distress**

To leverage debt, RE projects must be able to realistically meet their agreed debt service. Depending on the design of the CfD, fluctuations in the cash flow of the producer may be more or less pronounced. Liquidity reserves are necessary to hedge against fluctuations, but these involve high opportunity costs and should therefore be kept as low as possible. As CfDs have inherent risk of payback obligations, producers need to not only have liquidity reserves to pay debt but also to fulfil payback commitments. The exact impact of the payback commitment on required liquidity reserves depends on design of the CfD scheme.

### 2.2.5 Addressing 'missing' long-term markets

A discussed above, not only a profitability gap can be a showstopper for RE projects, but also price uncertainty. Besides uncertainties with regard to the long-term development of electricity prices, electricity markets are prone to price volatility, especially on the day-ahead market, the main market where RE electricity is sold in Europe. Price volatility is higher in electricity markets compared to many other markets because of several reasons. First, supply and demand need to be exactly matched to keep grids stable. Second, storage options are structurally expensive and thus limited compared to market volumes. In RE investments, most expenditures take place at the beginning of the project while operating costs are relatively small. To estimate a project's profitability, a long-term view on prices and thus revenues has to be developed, which is particularly difficult with regards to volatile electricity market prices.

CfDs provide a firm long-term outlook on achievable revenues per kWh. They are not the only contracts that do this. Markets offer futures (at the exchange trading platforms) and forward products (in over-the-counter trades outside of power exchanges). Such products fix the delivery price of a given amount of electricity in the future and hence provide price stability. A prominent option to stabilise prices via a forward product is a fixed-priced power-purchase-agreement (PPA). The PPA market is in a riveting development in Europe, with steadily increasing contract volumes. So, the question arises: if the market provides for price hedging instruments, why is there a need for public intervention in the market to provide long-term price stability?

While market options to hedge against price volatility exist, their availability is still limited – and too limited compared to the required RE expansion to meet mid- and long-term RE targets in Europe. For example, future products at power exchanges decrease in liquidity with each year of added duration. Liquidity of futures beyond three years is low even in very developed markets and non-existent in various European countries. However, RE investments typically require 15-20 years to amortise. In addition, trade at the power exchange typically needs to be backed up by liquidity reserves, putting limits to the total volumes available for trading futures. Moreover, futures for RE need to reflect the non-dispatchable nature of PV and wind energy, hence putting additional limits to this hedging instrument.

PPAs provide an alternative to futures traded at the power exchange, with durations of up to 20 years, fixed-price conditions and paid-as-produced options, i.e. fully aligned with the volatile feed-in of variable RE. However, PPA-market volumes (hence the availability of this hedging instrument) are distributed very unevenly across the EU, and many countries with large markets show only small PPA volumes for new RE installations.

PPA markets are limited for a range of reasons: PPA prices are linked to expectations on long-term price developments at the day ahead markets. If those are structurally below price levels needed to make the project commercially viable (including consideration of additional income from guarantees of origin), PPAs are not concluded. In addition, there are limitations on the side of potential PPA-offtakers: First, depending on the general electricity procurement strategy of the offtaker, they can only handle a certain share of fixed-priced and pay-as-produced PPAs from variable RE as it needs to be integrated into their procurement portfolio and ultimately matched with their load curves. Second, the credit rating of off-taking companies reflects the level of certainty at which the revenue of the RE project is actually secured via the PPA. A lower rating implies a higher chance of the offtaker defaulting on their commitment. The credit rating of most potential offtakers is worse than that of most MS (and MS support scheme are often the best alternative for RE projects) and often not good enough to enable suitable financing conditions for the RE projects. In addition, entering into a long-term PPA creates a liability for the offtaker, in turn negatively impacting the firm's credit rating.

Hence, market instruments exist to address the price risk that RE projects face, but their availability is very limited. This limitation can be interpreted as a market failure that requires an intervention, one option of which are CfDs. Support schemes in the form of CfDs provide the type of long-term price hedging instrument required for RE investments, albeit in form of a contractual relation between state (or an appointed implementing body) and producer, and not between two private market participants. Thus, they fill the significant existing market gap in long-term hedging instruments.

Some argue that when public CfDs are provided, the market would be missing incentives to develop such hedging instruments itself. However, the discussion of specific barriers for long-term price-hedging instruments and hence their limited availability has shown that against the background of massive RE deployment required until 2030 and beyond, public intervention may be well reasoned. In addition, the option for RE projects to access long-term price hedging via CfDs by no means implies that market-based hedging instrument would cease to exist – as long as CfDs do not shield against all risks (e.g., via longer averaging periods) or remain optional for RE developers. See chapter 5 for a more detailed discussion.

### 2.2.6 Trade-off between price stabilisation and market integration

The described core functions and impact areas are not independent of each other – there are several important interactions and connections between them. Sometimes addressing one specific area may involve having to accept compromises regarding others. These trade-offs also show in the distribution of risks between state and RE producer. When designing a CfD, trade-offs must be taken into account to optimise the design.

One typical opposing interaction concerns the CfD's alibility to address market integration on the one hand and addressing price risks on the other. Usually, an increase of market integration involves a higher exposure to price risks. Providing long-term income stability through a state support mechanism (like CfDs) reduces incentives to enter into market-based hedging products, like long-term PPAs. Interactions between these markets, spillovers and cross-incentives in price-setting have to be carefully examined.

In principle, the profitability gap is reduced best if income is stabilised at a profitable level. However, exposing RE producers to some sort of price risk is expected to incentivise their reaction to market signals and hence to incentivise market integration. Restricting the potential revenue for RE producers through a price cap and a clawback mechanism reduces risks of high prices for consumers but lowers the income potential of RE producers. This also removes part of the market signal, if the electricity market price is above the price cap.

# 3 Design of CfD options and implications

In the current discussion, CfDs are often associated with a certain design option, although there are manifold options for designing a CfD. For instance, CfDs are often associated with an hourly definition of the reference period, although longer time horizons have also been implemented and involve very different implications compared to a CfD with an hourly reference period. Overall CfD design can be broken down to individual design dimensions, which address different key functions and involve advantages and challenges. These individual design dimensions can be combined and applied as an overall CfD-package.

It is the objective of this chapter to explain the possible design dimensions. Some are discussed in more detail whereas others do not require a detailed discussion for the purpose of this report (such as duration of payment). Afterwards, we present and assess implications of different CfD design packages. Some design elements can be assessed in a general manner. However, depending on the potential combination with other design dimension, implications may differ from the separate consideration of each design dimension. One major differentiation in CfD design is the reference volume, which can be generation-based or generation-independent. Thus, we differentiate between these two categories of CfD design packages. Generation-based CfDs are the more classical ones that have been applied for several years while generation-independent CfD proposals are more recent. This analysis includes the most relevant design dimensions in the current context. However, there may be more design dimensions and of course more options of combining the different dimensions.

## 3.1 Design Dimensions

The most relevant dimensions for CfD design include issues related to reference volume, reference price design and further design elements, as shown in Figure 2. This section explains design dimensions, possible implementation options as well as respective consequences, and how the key functions and impact areas introduced above are addressed. The impacts often not only depend on one element, but how different elements are combined. Whilst some of the dimensions are discussed more in detail, others are briefly described in section 3.1.4.

| DIMENSION | Category | Discussed design options |
|---|---|---|
| Reference volume | Reference volume | ▪ Generation-based<br>▪ Capacity-based<br>▪ Generation-potential-based |
| Reference price design | Reference market | ▪ Day-ahead only<br>▪ Mixed price index (e.g. incl. intraday and balancing) |
| | Reference period | ▪ No aggregation (hourly / half hourly)<br>▪ Monthly<br>▪ Quarterly, Seasonal, Annual |
| | Referencing method | ▪ No averaging<br>▪ Technology-specific<br>▪ Technology-uniform RE<br>▪ Flat average (baseload price) |
| Further design elements | Strike price design | ▪ Cap-and-floor system (rubberband, bufferzone)<br>▪ Indexation<br>▪ Add-ons / Deductions |
| | Market integration safeguards | ▪ Payout limitations at negative prices<br>▪ Clawback limitations at low prices |
| | Contract design | ▪ Duration<br>▪ Administrative payment settlement rules<br>▪ Timing of referencing and payouts (ex-post, ex-ante)<br>▪ Exit option(s) for producer |

**Figure 2 Dimensions of CfD design**

### 3.1.1 Reference volume

One core distinction in CfD design is whether the payment is determined based on actual generation, on generation potential or on installed capacity. Generation may refer to the actual generation of the respective power plant, the average generation of a group of actual plants, or to a hypothetical reference, such as the theoretically possible feed-in of a reference plant. We shortly describe the mechanisms of the different designs choices and discuss their impacts in sections 4.2-4.4 below.

In generation-based payments, plant operators receive a premium per unit of electricity generated (in €/MWh). Since revenues generally increase with each unit of electricity generated, there is an incentive to maximise electricity generation.

In case of capacity-based payments (which are not by default CfDs), the payment is typically fixed per unit of generating capacity (in €/kW). The major advantage of the capacity-based payment is the avoidance of possible market distortions and inefficient behaviour by supported RE plants on short-term electricity markets. Provided that no support payment is linked to the actual feed-in, incentives to produce (or not) are based exclusively on market price signals. In particular, dispatchable power plants are automatically incentivised to operate in a flexible manner and contribute to improving market- and system-friendly behaviour.

In generation-potential-based payments, the volume used to calculate the premium payment is based on the generation of a reference plant or group in order to decouple premium payment from actual generation. Using the generation potential per installation (or installed capacity) still ensures a relation to the overall volume of electricity that could be generated by a power plant (or group of plants). The reference may either be the theoretical production potential of one specific power plant or a hypothetical power plant covering different locations, technologies, etc. For the pros and cons of these approaches, see section 3.3.

There are also combinations of the reference volume designs possible, as e.g. suggested in the “financial CfD” (see section 4.3.2), where capacity-based payments from the government to the RE producer are combined with payments from the RE producer reflecting the hourly day-ahead spot market profits/revenues of a reference generator.

### 3.1.2 Reference market and reference period

Second, the respective market(s) for determining the reference price must be chosen. In Europe, revenues for RE assets are mainly determined (either directly or indirectly) through the day-ahead spot market. This is also currently the predominant reference market for CfD implementations. But also intraday and balancing markets become more important. In principle, the reference price can comprise different market prices, with each their specific weights in the consideration. The further away from individually achieved market prices across segments (or revenues) the CfD is settled, the more basis risk the producer is exposed to. In the Spanish scheme, the sequence of electricity markets is considered by using a measure of price received to determine the difference payment for electricity sold on day-ahead and intraday market respectively (see the Appendix for details).

The applicable reference market price can be determined in different ways using different aggregation levels (periods). In its simplest form, it is taken as the most disaggregated price of the chosen underlying market (e.g. an hourly price on the central European day-ahead spot electricity market), and no aggregation or averaging is undertaken. But it can also be calculated as the average of any aggregated number of individual market prices over time (e.g. a monthly average of the hourly day-ahead market prices).

The aggregation works so that for each chosen reference period, the reference market price is calculated as an average of the individual prices (either weighted or unweighted, see section 3.1.3). Support levels (or payback levels) are determined by comparing the reference price to the strike price. This difference remains constant for each reference period, regardless of short-term market price changes within the period. The implications of choosing an averaging of reference price over multiple periods are profound: Within-period variations of market prices are passed through to the plant producer, thus conveying appropriate production signals and improving market integration (see section 3.2.3) without compromising long-term price stabilisation. The revenues experienced by the producer may become more volatile within the averaging period but are stabilised across periods – the amount of stabilisation (and introduced basis risk) depends on the averaging method, as discussed below. This insight is crucial in relation to the key functions of CfDs regarding bankability and market integration.

**Hourly definition of reference period**

In case of an hourly definition of the reference period, the plant operator receives the difference between the strike price and the market price in each hour of production and is therefore barely exposed to any price risks. There is a strong incentive to maximise production ("produce-and-forget"), which is typically considered in decisions for siting, plant design and plant operation. This also means that there are hardly any incentives for market integration (adjusting production according to current market price signals). The hourly reference period incentivises individual cost-minimisation of operation and maintenance, but not its system-friendly scheduling.

**Monthly definition of reference period**

Extending the reference period to a monthly level increases incentives to maximise market values instead of production. The premium payment is calculated using a monthly average of the underlying / reference price and is kept constant for one month. This makes price fluctuations within one month visible to power plant producers and therefore also provides stronger incentives to value-maximise maintenance within one month compared to the hourly reference period. However, the stronger incentives for market integration involve higher risks for plant operators and may lead to potential liquidity risks in case of large price swings.

**Quarterly, seasonal or annual definition of the reference period**

Implications of a quarterly, seasonal or annual definition of the reference period are similar to the monthly reference period, only that it adds the incentive to value-maximise maintenance across seasons. With an annual definition of the reference period, only longer-term price risks are hedged, while seasonal price fluctuations are experienced by plant operators.

It is also possible to define time horizons in between the described examples, such as a quarterly time horizon. Implications would place the quarterly definition between the monthly and the annual time period to establish the reference market price.

### 3.1.3 Referencing method

Besides the reference market chosen and the period over which the reference price is determined, the referencing method has strong implications on the risks allocated to the plant operator and on the incentives for market integration.

First, if no aggregation or averaging is undertaken (i.e. hourly period), no further consideration is necessary as to the referencing method, and the reference price is automatically plant specific. Several different referencing methods that involve averaging are possible for determining the reference market price. Here, the scope of consideration must be chosen. Logically, it cannot be the individual plant's production that is aggregated over the reference period, as then the averaging would not have any incentive effect. Therefore, some basis risk will have to be introduced. The further away from the individual plant's production the reference price is determined, the more basis risk the plant will be exposed to. The simplest form of aggregation is using the average baseload price in a certain market area as reference price for the chosen reference period. However, this price is often considerably higher than the achievable price for RE, due to merit order and cannibalisation effects. Hence, the RE plant will be exposed to high basis risk. Therefore, a referencing that is calculating as a weighted average of prices according to certain variable production volumes will provide a better hedge (more price stabilization).

**Technology-specific referencing**

A definition of reference prices at technology level would define a separate reference market price for each technology category such as wind onshore, wind offshore, solar PV, etc. In this case, the CfD pays the difference between the technology-wide average and the individual power plant. The market value of the technology becomes the reference for the plant. The plant achieves a full payout of the strike price and has full revenue stabilisation in case its production pattern perfectly fits the rest of the technology's feed-in. The producer is protected against the risk of decreasing market value factor (negative correlation between market price and production leading to overall lower achieved prices). Thus, the basis risk for producers is comparatively low. An upside can be gained by achieving a higher market value factor than the rest of the technology group in the reference, e.g. through plant layouting. However, there is only an incentive to "beat the siblings" within the same technology group, but not to improve compared to other technologies. Thus, this rather narrow definition only implies a medium system integration benefit.

**Technology-uniform referencing**

Choosing a broader scope for calculating the underlying/reference market price by using the market value of all renewable energy technologies implies higher risks for plant operators due to stronger deviations of renewable power plant profiles from the (synthetic) technology-uniform feed-in profile. At the same time the incentive to "beat the market" is stronger than in case of a technology-specific underlying implying large system integration benefits.

**Baseload reference market price**

The reference price can also be chosen as the 'flat' average of the underlying market, i.e. the day-ahead baseload price. This will leave the producer with full basis risk. Plant revenues will be structurally lower if the market value factor of the plant is structurally lower than the baseload market average. Uncertainty around future market values factors may lead to risk of decreasing revenues in this design. On the other hand, it gives strong incentives for market integration on both plant design and operational level.

**Examples for referencing methods and their effects on revenue stabilisation**

The quantitative example below illustrates the effects of different choices in reference price design. In Design 1 (no averaging), the producer always achieves the strike price in each period and has period-per-period stabilised prices. In the two other designs, the reference price is determined by averaging across a chosen number of periods (in this example five), and the difference between strike price and the average market price is paid out as a fixed premium in each period.

| | | Period 1 | Period 2 | Period 3 | Period 4 | Period 5 | TOTAL |
|---|---|---|---|---|---|---|---|
| | Own production volume [MWh] | 50 | 90 | 25 | 80 | 110 | |
| | Production of technology group [GWh] | 400 | 950 | 250 | 700 | 1250 | |
| | Strike price [EUR/MWh] | 120 | 120 | 120 | 120 | 120 | |
| | Market price [EUR/MWh] | 110 | 50 | 130 | 20 | 20 | |
| Design 1: no averaging | CfD payout [EUR/MWh] | 10 | 70 | -10 | 100 | 100 | |
| | Achieved price in period [EUR/MWh] | 120 | 120 | 120 | 120 | 120 | |
| | Revenues [EUR] | 6,000 | 10,800 | 3,000 | 9,600 | 13,200 | 42,600 |
| Design 2: volume weighted averaging | CfD payout [EUR/MWh] | 74 | 74 | 74 | 74 | 74 | |
| | Achieved price in period [EUR/MWh] | 184 | 124 | 204 | 94 | 94 | |
| | Revenues [EUR] | 9,200 | 11,170 | 5,100 | 7,520 | 10,350 | 43,340 |
| Design 3: flat averaging | CfD payout [EUR/MWh] | 54 | 54 | 54 | 54 | 54 | |
| | Achieved price in period [EUR/MWh] | 164 | 104 | 184 | 74 | 74 | |
| | Revenues [EUR] | 8,200 | 9,360 | 4,600 | 5,920 | 8,140 | 36,220 |

**Figure 3: Quantitative example of three reference price design choices (note: rounding simplifications for illustrative reasons).**

In Design 2, the reference price is determined by a volume-weighted average based on the technology's production volume, which corresponds to the achievable average market price by the technology group over the five periods, i.e. 46 EUR/MWh (sum-product of production volume and market price over all periods, divided by total production). The CfD payout is hence determined to be 74 EUR/MWh (120 minus 46). Note that the achieved prices (market price plus CfD payout) vary considerably from period to period, but the revenues remain more stable. Also, total revenues are very similar as in Design 1 for the overall averaging period, i.e. they remain fairly stabilised. The difference in overall revenue compared to Design 1 stems from the divergence of own production from the reference technology group. In the example, the production profile of the individual plant is less negatively correlated with the market price than the production profile of the technology group (market value factor is 73% as compared to 70%). Therefore, the overall revenues are somewhat higher than in Design 1. But they can just as well be lower. Note also that we avoid a situation of clawback in Period 3, as it is less likely that reference price exceeds strike price when averaged.
In Design 3, the reference price is determined by a flat, unweighted averaging of the market price (66 EUR/MWh in our example). In our example, this price is higher than the achieved price by the technology (48 EUR/MWh). Therefore, the CfD payout is lower than in Design 2 and total revenues decrease. This is generally likely, due to the fact that renewable technology often has systematically more production in low price hours and less production in high price hours (market value factors lower than one). Hence, the total revenues in the period are lower than in the other designs at the same strike price. This is an example of a transfer of profile price risk from state to producer. We would typically expect this additional risk to be priced into the CfD contract, and the strike price lifted upwards to ensure closing of the profitability gap (if it exists). In our example, a strike price of at least 138 EUR/MWh would emerge (deterministic minimum), 18 EUR/MWh higher than in the other designs.

### 3.1.4 Further design elements

Further possible design elements, requiring a decision on the implementation include contract design, strike price design and spot bidding incentives.

#### Strike price design

In principle, the strike price design may include indexation for different factors, such as inflation, commodity prices (e.g., steel and copper), labour and producer price indices, but they can also be implemented without any indexation. In addition, there is the possibility to use price adjustments such as boni/mali, a technology factor or a siting factor in order to incentivise intended purposes. Thus, a siting factor can be used to incentivise installations of wind power plants in less favourable wind areas in order to relieve grid congestion. In this paper we assume a strike price design without indexation and do not look at the different impacts of a potential indexation.

**Determination of strike price**

Contract design for CfD includes the process of determining the strike price of the CfD. One option is the use of an administrative procedure by the government, which typically requires excellent knowledge of the LCoE. The currently predominantly used option is to determine the strike price in an auction or in a competitive bidding process. Possible alternatives are use of an administrative procedure by the government or bilaterally negotiated procedures between the public entity and the power plant operators.

**Contract duration**

Another core element is how to define the limit of support payments to each plant operators. One broadly used option is to enable support for a fixed duration of e.g. 5, 10, 15 or 20 years. Alternatively, there is the possibility to define a volume-based limitation instead of defining the duration during which support is provided. Reasons for defining the contract duration based on a volume-based limit could be for example the wish to account for the occurrence of negative prices. Whilst a time-restriction may reduce the overall support volume with an increasing number of negative prices in case no support is paid in times of negative prices, a volume-based restrictions ensures a constant volume of remunerated electricity generation. This becomes more relevant if the number of negative prices correlated with productive RE generation hours increases.

**Additional contractual elements**

Another example of contract design is related to the settlement of payments, which can either be executed based on two-way payments or as a netted settlement, where the cash flows are consolidated into a single payment over a period. Here, special attention should be paid to final settlements at the end of the CfD contract, especially in case of possible premature exits.

One highly relevant issue is how to deal with possible combination with power purchase agreements. Thus, it must be determined whether combining CfD support will be made possible or whether the combination with PPAs is prohibited (see also chapter 4 for a more detailed discussion of the interactions of CfDs with market-based renewables deployment).

There are more possible implementation details with regard to contract design including the question of outstanding payments and potential future avoided clawbacks at premature exit.

## 3.2 Design Packages: Generation-based CfDs

The following section presents different options for generation-based CfD design packages, meaning relevant combinations of design choices. Generation-based support schemes are characterised by the fact that the support payments (and clawbacks) are directly linked to the actual production of the renewable energy plant. The general calculation is as follows, with potential modifications in the definition of the reference period, the implementation details of the clawback design and a combination with a cap-and-floor system.

$$\textit{Payment\_CfD}_t = (\textit{Strike Price} - \textit{Reference Market Price}_{\textit{Reference period}}) \times \textit{Electricity generation}_t$$

### 3.2.1 CfD with hourly reference period

**Description**

In the case of a CfD with an hourly reference period the reference market price is individual for each hour of the year. Therefore, deviations between the reference market price and the technology-specific market values are rather small and the CfD with hourly reference period is rather similar to the fixed feed-in tariff in terms of reducing investment risks.

**Discussion**

As shown in the calculation example (Figure 1), the benefit of the hourly reference period is a fully stabilised price and thus a high predictability of the achieved price in all hours during the CfD contract. Producers face no profile or basis risk. This also means that producers can optimise their revenues by maximising their production at all times – an incentive that might not be conducive to better market integration in systems with very high shares of renewable energy.

For the purpose of investigating market impacts, we distinguish two types of market distortions that can arise in connection to the CfD: First, incorrect production signal. This could either be to continue production even when prices are below marginal cost, or to stop production even when prices are above marginal cost and the system would benefit from it. Both situations may emerge, as described in the box below. Second, incentive for distortive (non-cost-based) bids that affect price formation. This can create market inefficiencies even without leading to physical (dispatch) consequences.

To safeguard market integration against wrong production incentives, payouts at negative prices need to be handled (see box). The design of the clawback is not an issue in the hourly reference period since spot market price signal and clawback are harmonised at all times (see also section 3.2.2). However, there may still be misleading incentives with regard to deviations between day-ahead and subsequent market segments (intraday, balancing). This is a general issue independent of the chosen length of the reference period but related to the disconnection of the payout/clawback from the individual market price. As mentioned above, CfD reference prices are typically defined from and fixed for the day-ahead market, but CfD payments also exert influence on the decision for or against production on downstream market segments such as intraday or balancing markets.

**Potential of wrong production incentives at negative day-ahead market prices**

For all generation-based CfDs, an issue arises from the distortion of production incentives during negative prices. In its simplest CfD design, the issue would be that, for example, at a strike price of 120 EUR/MWh and a reference price of -50 EUR/MWh, the difference to be paid out to the producer should be 170 EUR/MWh. Here, there is usually an agreed limit on the maximum level of payout, so that it cannot exceed the strike price itself, i.e. 120 EUR/MWh. But even this poses an issue, as it would leave our producer in the example with a profit of 70 EUR/MWh. In fact, it would incentivise the producer to sell power at market prices all the way down to -120 EUR/MWh in this example. This is a physical issue, as the electricity system would prefer the producers to curb their production (i.e. shut down), with the negative prices indicating oversupply in the system with limited flexibility options. But it is also a market issue, as it generally incentivises the producer to bid into the spot markets at their negative strike price (i.e. -120 EUR/MWh), functioning as their marginal profit threshold. This interferes with the general price determination mechanism of the pool.

The extent of distortions is different for hourly vs. averaged reference periods, as payouts are much more volatile in hourly reference periods than in averaged reference periods (see Figure 3), hence the production distortion will occur more often in the former design. This is also because in the hourly reference price the difference payment automatically reaches its maximum (the strike price) if negative prices are negative, whereas with longer averaging the difference payment is often less than the strike price. Thus, prices would not have to become as negative for producers under the CfD to stop production.

This distortive issue can easily be addressed by not providing support (pausing payout) during times of negative prices (with 0 EUR/MWh representing the marginal cost assumption of the RE producer), which re-establishes the correct bidding incentive in day-ahead markets. This, of course, then increases price and volume risk for the RE producer, who becomes more exposed to the risk of negative prices.

The additional exposure can be mitigated, if required. For example, in France (Dunkirk auction), a cap has been introduced on the number of hours during which payout is paused. When the cap is reached, support is still paid during hours of negative spot prices, but on the condition that the plant is not producing. This upholds efficient market bidding behaviour in the day-ahead market at all times (even when the cap is reached) while limiting RE producers' exposure to negative prices.

**Potential of distorted production incentives between day-ahead and intraday market**

For all generation-based CfDs, an issue arises from the interaction between market segments.
Even with all bidding incentives corrected at the day-ahead markets, intraday and balancing markets may still be affected by payout and clawback. This may lead to dispatch distortions from wrong production incentives on the one hand, and price formation distortions from changed bidding behaviour on the other. We distinguish the two effects, as certain market inefficiencies may be tolerable in some situations when not leading to physical consequences. We first illustrate potential distorted production incentives with the subsequent examples.

We have identified two situations in which changed incentives due to CfDs between market segments is an unsolved issue in regards to RE production: 1) during clawback when the reference price is high and intraday prices are positive but below the clawback; 2) during payout when intraday prices are negative but not lower than the (negative) payout. All other price situations and combinations may in principle lead to distorted bids, but with the right safeguards in place (e.g. dynamic clawback), there will be no production distortions.

**Distortion during clawback**

For example, at a reference price (RP, which in this example is equal to the market price) of 220 EUR/MWh and a strike price (SP) of 120 EUR/MWh, a RE producer has the incentive to sell at the day-ahead market, while being subject to a clawback (CB) of 100 EUR/MWh whenever they produce. The following is the basis for the revenue considerations: RP – CB = SP . Now, the producer may (instead of generating themselves) buy the volume they had sold on the day-ahead market on the intraday market, and while still satisfying their commitment from the day-ahead market, incidentally avoiding the clawback. This would be beneficial if they can buy at an intraday market price (IP) for less than 100 EUR/MWh (their opportunity cost), that is, whenever the intraday price is lower than the clawback (0 < ID < CB), which mathematically implies that the spread between high reference price and low intraday prices must be larger than the strike price (i.e., with RP – CB = SP, and ID < CB, we can conclude that (RP – ID) > SP). In this case, RE producers are incentivised to buy back their commitments from the DA market on the ID market and stop their own production to avoid clawback. As this implies RE curtailment at positive intraday prices (higher than the marginal cost of the plant), this would be inefficient and should be avoided.
To our knowledge, no one has so far in detail analysed how likely the situation (0 < ID < CB, or (RP – ID) > SP)) is and how significant the overall distortion would be. As an indication, Maciejowska et al (2019) report for the German market that between 2015 and 2018, the day-ahead/intraday spread (as a proxy for RP – ID) was on average 0.17 EUR/MWh, with a standard deviation of 4.49 EUR/MWh. This is far lower than a typical strike price (SP) in European CfD auctions. It should also be noted that for the situation to occur, a considerable price drop between day-ahead market and intraday market would be required, which typically occurs in situations with (unexpected) abundant supply or decreasing demand. Some excessive RE curtailment may in such situation potentially be tolerable. However, the effect should not be neglected, especially when contemplating larger CfD roll-out scenarios and increasing market influence by RE. It has to be noted that the effect occurs to different

extents depending on the chosen referencing method and period, as this affects the divergence between RP and SP, as well as RP and CB (the quantitative example in Figure 1 above showed, for example, that longer averaging periods avoid many clawback situations).

**Distortion during payout**

When the producer receives payout, it may influence the intraday bids, as producers may want to avoid foregoing the payment if curbing production. Producers should efficiently curb production if intraday prices fall below marginal cost (zero), but as long as the (positive) payout (PO) is higher than the (negative) intraday price, they will be incentivised to continue producing to avoid foregoing the payout, i.e. - PO < ID < 0. Hence, this is a situation in which producers continue to produce although the system would have benefited from their curtailment. It has to be noted that a similar issue arises in every existing generation-based RE support scheme implementation (also fixed and sliding premiums on the payout side), as all incentive designs have so far focused mainly on day-ahead market incentivisation.

**Potential of distorted bidding incentives affecting price formation on intraday/balancing markets**

Another issue is a potential distortion in the general price formation on intraday markets arising from the fact that producers will incorporate the CfD payout/clawback as opportunity cost in their bids on the intraday market. This creates an upward pressure on intraday prices during clawback, and a downward pressure on intraday prices during payout (Schlecht et al., 2024). For example, if the day ahead price is 70 EUR/MWh and the payout 50 EUR/MWh, then producers would only be willing to buy at the intraday market at prices below - 50 EUR/MWh instead of 0 EUR/MWh, because they can otherwise not maintain their profit margin (120 EUR/MWh). Such changed bidding behaviour constitutes efficiency issues even in situations in which no incorrect production incentives are present for the RE producer. Here, it should be noted that intraday markets are based on individual over-the-counter trades rather than a pool with a single price and that the issue is likely to have more effect on such markets, because of direct effects on individual deals. It may also lead to further distortion of price signals on other markets due to spillover effects. The overall impact of this phenomenon (short-term and long-term) still needs to be investigated. So far, RE support schemes have not dealt with this particular issue and have tolerated related distortions.

A solution that has been discussed by Elia is to discontinue payout under negative imbalance prices. But, as the imbalance price is a result of the overall system imbalance, this would make CfD payments dependent on RE producers' ability to predict real-time system imbalances, which again increases risk for the RE producer (Elia Group, 2022). Therefore, the discontinuation of the payout should be limited to the long volume of the respective balancing responsible party, and downward activations related to the balancing market should be included in the reference volume (Elia Group, 2022). Such solutions are so far in discussion stage only.

Another solution could be delaying the revelation of the CfD payout/clawback until after market closure, e.g. by determining the level ex-post (based on actual current prices rather than historic). However, this would limit the choices regarding referencing method, as averaging would make the payout/clawback predictable.

### 3.2.2 CfD with monthly, quarterly or annual reference period

**Description**

As described in section 3.1.2, the reference period for determining the payment (or clawback) amount (in EUR/MWh) can be monthly, quarterly or annual instead of hourly. Thus, the premium payment/clawback remains constant for each reference period and short-term variations in the market-based revenues are passed through to the producer. The design of the clawback is similar, but issues arise depending on the definition of the reference period.

**Discussion**

Using a longer time horizon for the reference period contributes to improved market integration with a view to seasonal, monthly and short-term price signals. However, some part of the price risk is allocated to plant producers, leading in general to higher revenue risks. Depending on the averaging method, the producers are subject to more or less additional risk.

Any kind of averaging period and method introduces a new issue during times of clawback. Whereas in the hourly reference period, there will never be a mismatch between payout/clawback and the current spot market price, this can easily happen in an averaged reference period system. One possible situation can here lead to undesired signals on the day-ahead market:

**Production-distortive incentive stemming from longer reference periods**
If, during a period of generally high market prices, a clawback is established, and then spot prices fall below the clawback during the period in which clawback is still being applied, producers may be wrongly incentivised to curb production.
This applies to situations with low but positive day-ahead market prices during a clawback period. Then, a producer may be incentivised not to offer production on the day-ahead market although prices are positive and thus above marginal cost (assuming zero marginal cost), if the day-ahead market prices fall below the clawback (DA < CB), as the clawback would then lead to overall net losses. For example, at a day-ahead price of 15 EUR/MWh during a 20 EUR/MWh clawback period, a producer would not offer any production on the day-ahead market, as otherwise they would incur a net loss of 5 EUR/MWh. This inefficient behaviour can be mitigated by dynamic clawback design (see below).

### 3.2.3 CfDs with monthly/quarterly/annual reference period and dynamic clawback design

**Description**

This option is based on the same design as described in 3.2.2, but varies the clawback design to avoid undesired production-stop incentives through distorted price signals occurring in situations of low short-term market prices as described above. For this purpose, the clawback is reduced in hours with low positive electricity market prices to maintain the incentive for RE plant producers to feed-in electricity in times of (low) positive prices.

For example, a rule that limits the clawback to maximum the current market price could have the following effect: when the market price is 15 EUR/MWh during a period of 20 EUR/MWh clawback, the producer would have an incentive to prematurely curb electricity production. But limiting the clawback to maximum the market price, i.e. 15 EUR/MWh (or, an amount just below that) would reestablish the production incentive on the day-ahead market.

**Discussion**

Interestingly, the introduction of a dynamic clawback design has no (or not much) of a revenue effect for the producer, but the system wins from the additional production in times with positive market prices.

Alternatively, a guaranteed minimum settlement price could be established with a similar effect. This minimum price would be paid for production under the CfD during positive spot-price hours, reflecting the marginal operating costs of a RE-plant, i.e. the expected direct marketing costs plus a margin.

### 3.2.4 CfDs with a cap-and-floor system

**Description**

Strike prices in CfD systems can either be fixed at a predetermined level or rather determined in combination with a corridor or a range for the market value. If the market value in the underlying reference period (e.g. one year) moves within the pre-defined corridor, no subsidy (positive premium) and no repayment (clawback) is due. If the market value in the reference period is below the corridor, a positive premium is paid as a sliding market premium. If, on the other hand, the market value in the reference period is above the corridor, a clawback is due. The premium/clawback is then determined in each case as the difference between the market value and the cap or floor limit.

Three approaches to determine the corridor have been discussed. First, the "Rubberband" approach, in which two different strike prices are defined, the floor used to determine when a premium is paid to the plant producer, and the cap used to determine the clawback. Second, the "Bufferzone" approach, where the strike price is the starting point for an administratively determined symmetrical corridor for the market value of e.g. +/- 10 EUR/MWh (alternatively +/- 10%). Third, the "Strike price as floor" approach, where the strike price determines the floor and the cap is added either as a "predetermined cap", an absolute (fixed) addition to the floor price or a relative addition on percentage base.

**Discussion**

Compared to the CfD options with a fixed strike price, CfDs with a cap-and-floor system lead to risk exposure of RES producers to price risks within the corridor. This option of designing a two-sided CfD can offer the possibility of preventing long-term markets from drying up. As the clawback does not take effect immediately, but offers a chance to benefit from market revenues, there is a certain possibility of participating in long-term markets, which is typically not incentivised in the case of two-sided CfDs with a fixed strike price. This option functions somewhere in between a two-sided CfD and a one-sided market premium, having similar effects as the combination of a market premium (one-sided CfD) and a clawback outside the CfD-system.
It should be noted that such schemes have not been tested as of yet, and there are concerns that bidding behaviour of actors may change compared to a two-sided fixed CfD, potentially incentivising bids below LCoE (as in one-sided CfDs), since uncertain revenues within the corridor can be factored into the bid. Further issues (such as distortions of bidding and production incentives) are similar to the other generation-based CfD options.

### 3.2.5 Discussion of generation-based CfDs

The direct linking of support payment to production output has been argued to have many advantages (see Kitzing et al., 2022). The main advantage has been the incentive to actually produce and feed electricity into the grid to realise revenues (e.g. in contrast to pure capacity payments). But it also bears some potential disadvantages, in particular in regard to market integration.

In the simplest generation-based CfD design, a continued payment of the premium may provide incentives to produce electricity, although electricity market prices are negative. Such potential disincentives can easily be addressed by not providing support during times of negative prices. Excluding support during periods of negative electricity prices is in fact a legal requirement from the EU state aid guidelines in order to avoid "market distortions". However, this exclusion leads to an increased volume risk for investors, as described in section 2.2.4. Thus, the volume risk in relation to negative prices has been introduced as a consequence of the political prioritization for market integration and the decision not to pay out support in times of negative prices. There are options of how to address the risk of negative prices, including the link of total support to total electricity feed-in, compensation payments or the possibility to catch-up "lost productive hours". Volume risk with regard to weather predictions is typically not addressed in generation-based CfDs. In this context, the question remains whether weather risk can be managed best by the producer or should be assumed by the public authority, and whether it is a risk that merits a cure within support design (such as financial CfDs, which come with their own challenges).

With regard to incentivising optimal dispatch and system-friendly design of power plants (e.g. larger rotors or hub heights for wind, east-west facing solar panels), the performance of generation-based CfDs largely depends on the determination of the reference period. In general, it can be said that the problem of “produce-and-forget” incentives, which CfDs are sometimes accused of, only appears if a reference period of the most disaggregated price (hourly, in continental Europe) is chosen. In principle, all reference periods longer than that allow short-term market signals to come through and provide incentives for short- or medium-term market integration (see also section 3.1.3).

Further, due to the clawback component and to retain the symmetry of payments between producer and state, the possibility to exit the contract prematurely should be generally excluded or at least cautiously designed in order not to allow for the avoidance of (future) payback obligations. If contracts are too flexible, RE producers may be incentivised to optimise the timing of exiting the CfD contract to maximise expected payout of support payments (e.g., a RE producer could exit the CfD contract after a period of low prices with payout and before a period high prices and clawback). This may lead to excessive overall support payments, which may be problematic from a societal perspective, and could also distort bidding behaviour and winner selection in a competitive support allocation procedure. Therefore, too flexible exit options should be avoided and incentives should rather be directed towards exploiting market signals.

There are also options of providing additional incentives to amplify the market price signal. However, in these cases one needs to be careful to avoid creating excessive incentives. An example of how to amplify market signals is the Spanish system, where support payments are adjusted to encourage increased production during times of high market prices (as described in 0).

Generation-based CfDs can be designed so that they are fully incentive-aligned and do not provide distorted incentives on the day-ahead market. This is, however, not the case when considering interactions between market segments. (Schlecht et al., 2023) point out that as soon as the payout (or clawback) is known to the producer, it constitutes an opportunity cost and will be priced into bids on the intraday and balancing markets. This might become an issue in some special cases.

## 3.3 Generation-independent CfDs

Generation-independent CfDs have been proposed in different forms by Newbery (2021, 2023a), Elia Group (2022), Schlecht et al. (2023, 2024), and were already discussed by

Barquín et al. (2017). All proposed designs aim to address the dispatch distortions caused by conventional (generation-based) CfDs on day-ahead, intraday and balancing markets (see section 3.2.5 for an explanation of these distortions) by decoupling the CfD payment from the actual infeed of the RE installation. In this sense, they are similar to traditional capacity-based payments, where the payment is fixed per unit of generating capacity (in €/kW), but they have some improved incentive features. Since no support payment is linked to the actual feed-in (as is the case in generation-based schemes), incentives to produce (or not) are based exclusively on market price signals and, hence, bidding distortions on the electricity markets are inherently avoided. A major drawback of traditional capacity payments is that they provide little investment certainty because they do not hedge RES producers against long-term electricity price risk, which is a major risk for non-dispatchable RE technologies like wind and solar. Another drawback of capacity-based support payments is that they may provide unintended incentives with regard to plant design (e.g. rotor-to-generator ratio of wind power plants) and may lead to oversizing of plants by maximising capacity and not electricity output. The recently proposed generation-independent CfDs aim to keep the advantage of capacity payments but increase investment certainty of RE producers and plant layouting incentives by linking the support payment or payback not solely to the installed capacity, but to the generation-potential of reference plant or reference group. Thereby, they still ensure some relation of the support volume to the overall volume of electricity that could be generated by the RE power plant. Newbery (2021, 2023), Elia Group (2022), and Schlecht et al. (2023) make different proposals for how the reference volume could be determined, ranging from a close estimation of the individual RE plant's generation potential to a broader estimation based on a larger group of generators. Also, their proposals for determining the CfD payment itself differ. In the following sections 3.3.1 to 3.3.3, we summarise the design proposals. In section 3.3.4, we discuss some strengths and weaknesses.

### 3.3.1 "Capability-based CfD"

**Description**

The concept of a "capability-based CfD" was proposed by the Belgian TSO Elia (Elia Group, 2022). While it has been debated across Europe and is implemented for the next Belgian offshore wind tender, there is no publicly available document by Elia describing the concept in detail. We therefore refer to some non-papers by Elia as well as a characterisation by Schlecht et al. (2023).

The main aim of the concept is to remove the dispatch inefficiencies created by the price signals of generation-based CfDs on day-ahead, intraday and balancing markets. This is done by decoupling payments from actual production, relying on a RE installation's potential to produce (capability) to determine the support payment:

$Payment_t = (strike\ price - market\ reference\ price_t) \times production\ potential_t$

The production potential is defined per RE installation, i.e., based on the installation's capacity and its specific meteorological, topographical and technical conditions, such as measured wind-speeds and turbine-specific power curves, but also reflects plant-specific downtimes, such as curtailment requested by the system-operation. The rationale is to precisely reflect the amount of MWh that the installation could have produced over a specified period of time (e.g., month or year). The concept is inspired by the baseline methodologies Elia has developed for the automatic frequency restoration reserves for wind and solar PV, "calculating the wind or solar PV generation that would have taken place in case no downward activation would have taken place (i.e., the so-called "Available Active Power" or "AAP") based on real-time measurements such as wind speed or solar irradiance (calculated baseline methodology)" (Elia Group, 2022). It should be noted that the AAP may need manual corrections when plants are unavailable, depending on reference volume design choices. The capability-based CfD also resembles the concept of Newbery's yardstick CfD (see section 3.3.3), even though the latter is not specifically referenced.

**Discussion**

By measuring the installation-specific production potential, the plant operator's risk of deviating from the reference (basis risk) is minimised, at least in theory. However, there seem to be substantial implementation risks for this capability-based CfD model. Discussions that we had with practitioners indicate that the measurements needed to determine the production potential for each specific reference period are either unreliable or very expensive, especially for wind energy, to a lesser extent also for solar PV. Furthermore, there are concerns about data sharing and the possible manipulation of such measurements. It remains to be seen how these challenges are solved in the Belgian offshore tender. In relative terms, the measurement costs per kWh of electricity produced would be substantially higher for wind onshore than for wind offshore.

Because the reference for determining the CfD payment is the individual RE installation, there is no potential to optimise the location of the plant compared to the reference (this is criticised by Schlecht et al. (2023), see below), which is a logical consequence of trying to minimise the basis risk.

The market reference price is not specified by Elia, but in principle the same reference price periods as for generation based CfDs can be applied, i.e. hourly, monthly or yearly averaging, with the same pros and cons as described in section 3.1.2. (i.e., stronger/weaker market integration incentives, but also increased/decreased deviation risks). It should be noted that monthly or yearly reference prices do not lead to any dispatch distortions, contrary to generation-based CfDs.

### 3.3.2 "Financial CfD"

**Description**

The concept of a generation-independent financial CfD was first proposed by Schlecht et al. (2023). The aim is to hedge the price risk of RE producers while avoiding the distortive dispatch incentives of generation-based CfDs (similar to Yardstick CfD and Capability-based CfD) and, additionally, to address the weather-related volume risks faced by wind and solar plants by making the payment weather-independent.

Drawing parallels to future and forward contracts used in electricity trading, which are financial derivatives, Schlecht et al. call their design proposal "financial CfD". The financial CfD payment is an hourly payment between the government and the contracting generator, which is defined as the net difference between two components: 1. a fixed hourly (capacity) remuneration determined upfront in an auction, which is independent of actual generation or weather conditions, 2. an hourly payment by the generator to the government, which equals the hourly day-ahead spot market profits/revenues[3] of a reference generator.

The reference generator is not an individual RE plant, but "a method to determine an hour-by-hour generation profile that matches the production of contracted assets closely". Schlecht et

[3] In case of generators with operational costs, the profits are defined as the day-ahead spot price minus operational benchmark costs. For wind and solar, profits may be defined as market revenues, assuming that these technologies have close-to-zero production costs.

al. explain that the price hedge of the reference generator improves, the closer the RE individual plant's production is to the reference. The higher the basis risk (=deviation risk) originating from the difference between the reference generation profile and the plant's own production profile, the higher the revenue risk. Schlecht et al discuss different possible approaches for defining the reference generator for wind and solar without making an explicit recommendation for one of them:

- A mathematical model that derives reference output from measured, regionally aggregated weather data; the authors argue that such an approach would not be a perfect hedge for any specific plant but could still be sufficiently good. They see a manipulation risk if weather measurement techniques change over time or if strategic actors influence weather models.
- A sample of actual physical wind or solar farms; this option is not favoured by the authors because of the financial incentive to manipulate the dispatch of these reference plants.
- The aggregated wind or solar generation of a country or bidding zone; the authors mention the caveat that for small zones with few large generators, such as offshore bidding zones, there would be a risk of gaming the reference.
- A technology-neutral base profile (i.e., the unweighted spot market price of a bidding zone), which would increase the basis risk for RE generators but incentivise system-friendly plant design and introduce cross-technology competition.

As an additional design feature, Schlecht et al suggest that the government should require a collateral (i.e., a security) to back-up the CfD contract, similar to the financial collateral required for future contracts. To avoid liquidity problems, they propose that the government could accept the contracted physical generation assets as collateral.

**Discussion**

The financial CfD deviates from other CfD concepts in the sense that it is a novel payment construct that combines a capacity payment by the government with an hourly payback by the generator that is determined by a reference generator. The payback is therefore not only generation-independent, but it is also not related to an explicit strike price. It equals the full hypothetical market revenue of the reference generator. This payment construct appears complex on first sight but is fully incentive-compatible once the installation is built. Compared to conventional CfD schemes, it would imply a significant change in the bid calculation of RE investors applying for support payments.

A new element of the financial CfD that has not been addressed by other CfD models is the elimination of the weather-related volume risk. The latter is well known to wind and solar producers and therefore has not been identified as a major obstacle to RE investments, but it may increase with changes in weather patterns related to climate change. The authors argue that the elimination of the weather risk may offset the newly created basis risk. Whether this is true would need to be assessed in quantitative terms and would largely depend on the size of the basis risk related to the reference generator chosen. As described above, Schlecht et al do not recommend one specific reference generator but discuss different options with lower or higher basis risk for the RE producer. However, they stress the benefits of a generic base profile as reference generator, which would expose RE producers to higher basis risk than other variants. While it is true that such technology-neutral reference would introduce cross-technology competition, it contradicts the intention of introducing technology-specific RE support schemes and reference prices: reducing the investment risk for wind and solar by reflecting their generation profile (see section 3.1.3). It therefore appears questionable whether such a technology-neutral reference generator would be a suitable fit for a technology-specific support scheme.

On another design choice, Schlecht et al also argue in favour of higher risk exposure: while Elia Group (2022) propose to exempt periods of structural unavailability of wind and solar plants from the CfD payback, Schlecht et al stress the advantage of such payback risk: In times of low electricity prices, unavailability becomes cheaper and in times of high electricity prices unavailability becomes more expensive compared to traditional CfD settings. In other words, the unavailability of the power plant is correlated to power prices, which provides a higher incentive to make the plant available in times of high prices. This sends the right signals from an overall market perspective, but creates significant risks for the RE producer, who will face high payback in times of high market prices, despite not being able to produce. On the other hand, there is also an upside: the producer will still receive the capacity payment, without producing any electricity.

### 3.3.3 “Yardstick CfD”

**Description**

The Yardstick CfD is a concept proposed by Newbery (2023) (in earlier versions of the paper called Premium CfD, see Newbery (2021)). It was developed before and independent of the capability-based and financial CfD, but has some common features. The aim is to address location and dispatch distortions of conventional CfDs while still providing investment certainty.

Newbery acknowledges that capacity subsidies in the form of a fixed subsidy per MW avoid dispatch distortions, but fail to hedge future market risk. To provide such hedge, he argues that the capacity payment shall be determined with “a yardstick highly correlated with predicted hourly output but independent of the actual output.” He therefore proposes a financial CfD in which the contracted volume in any hour is equal to the developer’s hourly forecasted output per MW capacity (“yardstick volume”).

However, to keep the incentive to locate in areas and/or choose plant designs that minimise correlations with the overall wind/PV infeed, he also considers setting the yardstick volume at the system-wide average of all wind or PV installations, rather than the local average output (as described initially).

Furthermore, he identifies locational distortions of generation-based support payments. He argues that they over-reward high wind and solar resource areas where producers can reach high full-load hours, rather than locations that deliver renewable electricity at least system cost. He therefore proposes to determine the length of the contract not by time but by the number of full operating hours.

**Discussion**

Newbery’s CfD design proposal is less detailed than Elia’s capability-based CfD but conceptually very similar in the sense that it proposes to determine the generation potential of an individual RE installation. This would limit the basis risks for the RE producer. His alternative proposal of setting the yardstick volume at the system-wide average of all wind or PV installations is closer to the ideas of Schlecht et al and would increase the basis risk accordingly. A new element is the discussion of locational distortions. Newbery’s proposal to pay support not for a fixed period of time but for a fixed volume of full-load hours per MW would have implications that go beyond the described avoidance of locational distortions. It can be noted that such production-volume based contract length had successfully been implemented in Danish offshore wind auctions in the past. Compared to conventional CfD schemes, such a model would reduce the revenue risk of foregone support payments, e.g., due to changes in weather, but it may create new implementation challenges, e.g., regarding the determination of the adequate number of full-load hours.

### 3.3.4 Discussion of generation-independent CfDs

Generation-independent CfDs are conceptually appealing, as they automatically incentivise producers to contribute to improving market- and system-friendly behaviour, and make necessary measures to safeguard market integration redundant. We see it as the biggest advantage of generation-independent CfDs that they avoid market distortions identified for many design options of generation-based CfDs: they provide no incentive to feed in at negative market prices or to artificially curtail RE plants to optimise day-ahead or intraday trading. At the same time, they maintain the potential to provide a sufficient level of investment certainty to RE investors: if designed and implemented correctly, they may hedge the long-term electricity market price risk and provide a predictable payment stream to RE generators. In particular, they could solve the problem of pausing support payments in times of negative prices, as required by European State Aid Guidelines[4], which becomes an increasing risk under generation-based support schemes. Under generation-independent CfDs, support payments would no longer be related to individual production and would therefore not provide the incentive to feed in at negative prices, therefore the rule should not be applicable. The proposals by Schlecht et al. and Newbery would take out additional volume risks (e.g., related to weather changes), by ex-ante fixing the reference volume.

One disadvantage of generation-independent CfDs is that they introduce a new basis risk for RE producers, i.e., the risk of deviating from the volume reference that determines the CfD payment. In principle, such basis risk can occur in all generation-independent CfD schemes, but in different forms and to different degrees. In case of site-specific resource measurement, as suggested for the capability-based CfD, the basis risk is comparatively low, but depends on the quality of the measurement. For wind energy, accurate measurements would likely require capital-intensive laser-based measurement technologies (Light Detection and Ranging - LiDaR). Without these technologies, there is the risk that actual measurements may deviate substantially from the plant's actual production. However, the issue of suitable measurement techniques requires further research. Furthermore, there is a risk of manipulating measurements in order to increase the potential income from the support scheme. Using producer-independent, external weather data by professional data service providers may provide more objectivity, but the deviation from the plant's actual production risks to be high and not easily predictable, at least for wind energy, where wind yields depend heavily on site-specific conditions. Using a reference profile consisting of aggregated weather, generation or market price data may increase the market integration incentive compared to site-specific approaches, but comes with a significantly higher deviation from individual production profiles and therefore increases the basis risk. At the same time, such aggregated data is not subject to individual measurement errors or manipulations and may still be predictable.

Further examination is required to assess how well RE generators can predict and hedge the different types of basis risk and how RE generators perceive the new basis risk. It is still to be decided which reference models would be most suitable in terms of resulting incentives and practical implementation. It is also as of yet unclear how availability of plants would be handled and integrated in the reference volume considerations. This may or may not increase the exposure of producers.

A likely shortcoming from the perspective of the paying government is the missing link between support payment and actual RE production, which has been emphasised as one of the major advantages of generation-based support for RE (see Kitzing et al., 2022). Due to its practical advantages, policy makers across the world have implemented generation-based RE support (despite its flaws in terms of market efficiency). Compared to the traditional capacity-based

[4] See section 3.2.5

support schemes, in which installed capacity is incentivised but not RE production, the discussed generation-independent CfD designs perform considerably better in terms of providing production incentives. . Since the discussed generation-independent CfD designs are based on production potential, they come a step closer to target-alignment. There still remains a risk for governments to paying support without achieving RE in-feed. However, the risk of non-production in the discussed generation-independent CfD designs appears to be quite low for mature RE technologies, where business cases depend mostly on market revenues rather than on support payments.

Finally, all generation-independent options introduce new implementation risks for RE producers and governments, in particular increased complexity, and risks of incorrect parametrisation. This does not necessarily speak against generation-independent CfDs per se, but the missing practical experience with their implementation appears challenging. Contrary to the generation-based CfD models presented above, which have been implemented in several countries (see the Appendix for implementation examples), generation-independent CfD models are still in a concept stage. The Belgian implementation of capability-based CfDs for offshore wind is progressing, but practicality remains to be proven. The financial CfD and the yardstick CfD are even more conceptual in the sense that the authors discuss different design options without recommending a detailed design.

To conclude, from a conceptual perspective, generation-independent CfDs appear to be superior to generation-based CfDs in particular with regard to providing undistorted price signals. However, whether their advantages can materialise in practice will depend on how well their implementation challenges can be solved. It should not be neglected that in many countries, generation-independent designs will be more disruptive to the existing support landscape than generation-based CfDs.

## 3.4 Comparison of all options with regard to addressing risk factors and enabling market integration

Finally, we compare the discussed design packages with regard to selected risk factors and their ability to enable market integration.

In general, we note that price risk exposure is not directly related to the choice between generation-based or generation-independent only. This is different for volume risks. While the risk of negative prices can be handled in both types of schemes, exposing plant operators to weather risk exposure for plant operators is mainly addressed in generation-independent schemes that define the support volume independent of weather-related conditions (i.e. in financial CfDs and Yardstick CfDs, but not in Capability-based CfDs). Further differences in regard to allocation of risks are related rather to the amount of basis risk that producers are faced with. This is to a large extent dependent on the choice of referencing method and period – a choice that needs to be made for every scheme.

In addition to that, the new proposals on generation-independent CfD design introduce a new basis risk related to volume, stemming from the fact that the reference volume can deviate from the actual production volume of a producer. In fact, the producer may now be subject to a "double reference", on both price and volume, with exposure to deviation from the actual obtainable value for the individual plant. The level of basis price risk for all CfD types depends on the referencing method and period (where hourly referencing generates the least (or no) exposure). The level of the basis volume risk introduced within the generation-independent CfDs depends on its design. Whilst a narrower definition close to the production potential of the individual plant means a low additional basis risk, a broader definition taking technology or market averages involves increasing potential deviations in the electricity production of the plant from the defined basis.

The additional risk exposure materialises in greater uncertainty of revenues, and can lead to either higher or lower revenue outcomes. It opens up the opportunity for ‘beating the reference’ and therewith obtaining additional profit, and it opens up for performing worse than the reference. The incentive to 'beat the reference' can be strategically used in RE support scheme design to increase market integration of RE. Each implementation should carefully balance the specifically suitable basis risk exposure and market integration. For some of the recently suggested proposals on generation-independent CfD-design, it is still difficult to evaluate the basis risk, since not all the details have been specified sufficiently for a clear evaluation.

**Table 2 Comparison of discussed design packages with regard to addressing risk factors and enabling market integration**

| | Addressing risk exposure for RE producers | | Exposing RE producers to basis risk (reference deviation) | | Enabling market integration | Challenges and remaining issues / Implementation issues |
|---|---|---|---|---|---|---|
| | Price | Volume | Price | Volume | | |
| **CfD with hourly reference period** | No exposure | Normal production risk exposure | No exposure | No exposure | "Produce-and-forget" incentives, hardly incentivises market integration, intraday distortions | Lacking variable short-term price signals hinder market integration |
| **CfD with hourly reference period, payout paused during negative day-ahead prices** | | * | | | "Produce-and-forget" incentives for positive DA prices, improved market integration for negative DA prices, distortions on intraday and balancing markets | Lacking variable short-term price signals hinder market integration |
| **CfD with monthly, quarterly or annual reference period** | | * | ** | | Provides short-term/seasonal price signals, creates bidding and production distortions on day-ahead, intraday and balancing market | Design in times of clawback, remaining DA-ID distortions |
| **CfD with monthly/quarterly/ annual ref. period and dynamic clawback design** | | * | ** | | Provides short-term/seasonal price signals, DA-distortions are addressed, intraday distortions persist | Determination and implementation of dynamic clawback design, remaining DA-ID distortions |
| **CfD with a cap-and-floor system (and market integration safeguards as above)** | | * | *** | | Price signals depend on ref. period similar to above, price signals passed through within corridor, ID and DA distortions similar to CfDs above. | Determination of Cap /floor parameters; Fewer issues with "drying up" of forward markets; Lower pay-back to consumers than in other CfD variants |
| **Capability-based CfD** | *** | | *** | | Short-, medium-, and long-term market integration ensured<br>No DA and ID distortions | Potential measurement and manipulation possibilities (or their prevention). |
| **Financial CfD** | *** | No exposure to negative prices, additionally removes weather risk | (***) | **** | Short-, medium-, and long-term market integration ensured<br>No DA and ID distortions<br>In case of aggregated reference: incentive to optimise plant location | Complexity and implementation issues, dealing with "collateral", possibly implications of classification as financial derivative and consequences for small players. |
| **Yardstick CfD** | | Potentially removes weather risk | *** | | Short-, medium-, and long-term market integration is ensured<br>Locational distortions are addressed | Design details not specified |

CfD: Contract-for-difference; DA: Day ahead; ID: Intraday; RE: Renewable Energy

* In implementations that do not provide support (pause payout) during times of negative day-ahead prices, RE producers are more exposed to additional revenue loss from negative price hours. In principle, these losses may be priced into strike price bids, but due to their uncertainty of occurrence in the future, this can be a challenging (and hence risky) task.

** The extent of risk exposure is dependent on choice of referencing method (the further away the reference from individual market value, the higher the exposure)

*** Similar design choices as for generation-based CfDs on reference method and period (hourly, monthly, quarterly, annual)

****Depending on (currently unknown) choices regarding determination of reference volume

It becomes apparent from the visual comparison of all discussed CfD design packages that all options come with their disadvantages, and that trade-offs as well as compromises are necessary when deciding on a CfD implementation. Compared to generation-based CfDs, generation-independent CfDs show some fundamental advantages, mainly related to market integration, but also severe challenges, mainly related to implementation issues.

In addition to the design packages discussed here, adaptations in the CfD designs can be undertaken to address open issues in each design. Many solutions found for one option may also be applicable for other options, which would change the risk picture of those designs. For example, we indicate a volume risk related to exposure of negative prices in generation-based CfD packages, but the volume-based contract length suggested in the Yardstick CfD may mitigate this issue for other options as well.

Further issues not shown in the table, as for instance the required regulatory changes and subsequent market adaptions compared to the existing schemes, also need to be considered. These may change the perceived risks of investors and may also substantially impact their investment behaviour, depending on the severity of change in the support scheme.

# 4 Interactions with market-based renewables development

As argued in section 3.2, CfDs are addressing a market failure expressed in the lack of sufficient long-term price hedging instruments that – without intervention – would likely lead to renewables targets not being met in the EU. The introduction of CfDs for RES creates various interactions with market-based RE deployment, which is coexisting with public support-driven market development. As in particular additional RE capacity required to achieve targets involves variable RE, we conceptually assess the potential interactions of CfDs for variable RE and the market-based RE development. This conceptual assessment is a first step – a more detailed analysis requires a differentiation for onshore technologies (PV and wind onshore) on the one hand and offshore wind on the other, as well as further empirical data.

**Basic interactions**

For onshore technologies, CfDs could be implemented as an option for RE project developers, i.e. not as a mandatory program. In this case, project developers can choose to participate in a competitive bidding scheme to access CfD as a means to mitigate price risks (long-, medium- and short-term risks depending on the reference period) and to close any profitability gap. Alternatively, they can develop projects outside of the CfD scheme and hedge prices via long-term PPAs. Initially, CfDs require a binding decision by the project developer for either the CfD or the PPA-based marketing route because allowing the option to exit a CfD scheme prematurely without substantial penalties would allow producers to circumvent payback obligations at times of electricity prices above the strike price. This would undermine one of the central functions of the CfD scheme, namely the capping of revenues and redistribution to end-consumers.

Prohibiting a switch between CfD-payments and PPAs within a CfD scheme may lead to a clearer market segmentation in a first instance (i.e. a PPA market and a separate segment of CfD-based RE deployment) because a RE installation will usually stabilise revenues either under a CfD or via a PPA. Whether the CfD or the PPA is more attractive from an investment perspective depends on the conditions in each option, foremost the expected PPA price vs. the realisable CfD bid in the auction. Bidders in CfD auctions usually do not bid below LCoE (as a proxy for project profitability), whereasPPA prices are linked to expected electricity prices at the wholesale market. In a hypothetical low-price scenarios with (captured) electricity market prices below LCOE, a PPA would likely not generate sufficient revenues and theoretically no PPAs would be feasible. In a hypothetical high-price scenario, PPA and CfD prices should tend to converge until indifference is achieved. Then, bids in the CfD auction will factor in potential PPA prices. The price convergence effect may be limited in practice, however, by various factors: 1) the size of the PPA market potential (which is limited by various factors, including limited credit rating of offtakers); 2) volumes in the CfD auction as well as ceiling prices. The share of projects that will be realised under CfDs as compared to PPAs depends on the relative attractiveness of either option and on the additional PPA market limitations (as discussed in section 3.2.3); 3) PPA prices would be corrected by higher cost of capital due to higher counterparty risks compared to the CfD, resulting in a final gap between CfD and PPA prices.

**Interactions in offshore wind**

For offshore wind, interactions between CfDs and PPAs differ slightly compared to onshore technologies, since access to sites is typically organised centrally. Hence, the decision to implement a CfD or to ask for PPA-based financing is typically taken by the responsible public entity and not by the project developer. As a result, the outside option of PPAs is less evident and hence less likely to be priced into the CfD bid.

However, there are options to combine CfDs and PPAs on various levels. For instance, in offshore auctions in the UK (Seareen and Moray West) each project can define the share of the project that is covered by the CfD scheme vs. the share that is covered by a PPA. In this sense it is up to the market to define the required share of public hedging of price risks and the available support budget can be distributed over various projects. In Belgium, upcoming offshore auctions (Princess Elisabeth) allow project developers to participate in the auction to secure a CfD and to partially exit the CfD. This can happen up to 3 years after entry into operation to secure a PPA for up to 50% of the project (an additional 25% can be carved out for the PPA if the project is related to energy communities). Project developers cannot substantially avoid the payback obligation in this scheme by exiting the CfD, as they are allowed to add only 3€/MWh to the strike price to determine the PPA price. Producers can use the CfD as a fallback option if the offtaker defaults. The Danish CfD scheme indirectly allows parallel PPAs on the same volumes as those contracted under the CfD (evidenced by PPA contracts for e.g. Kriegers Flak). The Irish CfD scheme inherently integrates PPAs in their payment design (see Appendix A.5)

These examples from offshore wind show that CfDs and PPAs do not have to be as mutually exclusive as the initial securing of payback commitments would seem to require. Other concepts to provide more flexibility between CfDs and PPAs could be to allow producers to exit a CfD, but to penalise the re-entry into a CfD with a discount on the initial strike price; to introduce substantial exit-fees that are linked to expected future clawback amounts; or to allow limited pauses of CfDs based on predefined rules. However, these options would need to be further developed and investigated to limit circumvention of payback obligations. Another potential workable solution that has been discussed to ensure co-existence of CfDs and PPAs is through carve-out of volumes from the CfD contract, so that e.g. only 80% of an individual plant production is contracted within the CfD, leaving an incentive to conclude a PPA for the remaining volume. Potential implications on bidding behaviour and related auction inefficiencies should be investigated.

**How Guarantees of Origin come into play**

The limitations to switching between a CfD and PPA and interactions between them depend on the regime on Guarantees of Origin (GOs). In some Member States, GOs are not issued (or issued and immediately cancelled) for electricity production that has received support, e.g. in Germany. In other Member States, e.g. in France, GOs are centrally auctioned and the revenues are used, for instance, to reduce levies for consumers. The choice to “remove” supported green electricity from the GO market has to be assessed in the context of the larger framework of industrial policy. One may argue that industrial policy supportive of the green transition of key European industries requires easy and affordable access to GOs.

Several governments, such as NL and DK, have opted to issue GOs also for supported electricity production. These can be used in 'green' PPAs which in this case can be established simultaneously to receiving support payments for the same production volumes. Support levels theoretically can be reduced to the extent that GOs have value for their offtakers.

In the context of CfDs it is ex-ante not entirely clear whether an individual plant over the whole contract period will have received net support or whether the producer made overall net payments to the state. It would in any case be regarded as support, as the public provides price stabilisation via the CfD. However, the uncertainty on whether producers receive net support may provide some grounds for rethinking the issuance of GOs and potentially loosening limitations on the trading GOs from publicly supported electricity production.

# 5 Conclusions

We have presented the major application and impact areas of Contracts-for-Difference in a European context, described the most relevant design dimensions, and discussed several design packages for CfDs as combinations of distinct design choices. We distinguished between generation-based and generation-independent CfDs and discussed these separately as well as in comparison. We provided an overview of implemented CfD schemes in Europe.

We have done this to create an informed and objective basis for discussion of CfD designs to support the European discussion about CfD implementations as a major mechanism for RE support. It becomes apparent that CfDs are much more diverse than what it may seem like at first glance. Design specifications are highly complex and can be used in many different specifications and combinations. In this, the design choices that are adequate for a specific CfD implementation in a country and market situation will always be highly context-specific and evolving over time.

Generation-based CfDs have been applied in a variety of European countries. We find that the breadth and variety of design options of generation-based CfD are sometimes not sufficiently acknowledged and hence assessments of design alternatives are based on a partial foundation for comparison. For example, the notion that generation-based CfDs provide "produce-and-forget" incentives and mute exposure to short-term electricity price variation is only true for a very specific design of CfDs (i.e. hourly reference prices). Most CfD schemes on the European continent have long left this issue behind. It is possible to design incentive-compatible CfDs that do not distort bidding behaviour in the day-ahead market. Such designs include exposure to short-term variability (through averaging as referencing method), pausing support payments when no production is desired (e.g. at negative day-ahead prices), and a dynamic adaptation of clawback. Other challenges remain, including distortive effects and spill-overs from day-ahead to intraday and balancing markets (risks dispatch inefficiencies, exaggerated down-regulation and delayed production stop), which still need to be addressed in further conceptual development. It remains to be assessed how relevant/severe the market distortions across market-segments from generation-based CfD are, and how they should be handled when RE volumes under CfD schemes rapidly increase in a wider roll-out.

Generation-independent CfDs are new and conceptually appealing. A main argument brought forward by advocates for generation-independent CfD is that they address certain market distortions that remain in generation-based CfD: they provide no incentive to feed in at negative market prices or to inefficiently stop production. A structural disadvantage of all proposed generation-independent CfDs is that they introduce a new basis risks for RE producers, i.e.

the risk of deviating from the reference volume that determines the CfD payment. RE producers may thus be exposed to a “double reference” risk. Such basis risk can occur in all generation-independent CfD schemes, but in different forms and to different degrees. The existing proposals are partly rather vague in terms of how to determine the reference volume. This point needs special attention when implementing such CfDs, as all risks for producers should remain manageable, otherwise support scheme will become less effective. All suggestions for generation-independent CfDs have open implementation issues. Substantial issues that need to be clarified for generation-independent schemes include, next to the basis risk, that e.g. models using generation-potential face challenges with regard to potential manipulations of the required measurements of weather conditions and the absence of adequate external determination of production potential. It should also be considered that the introduction of the new proposals of generation-independent CfD options may require a substantial system change leading to a potential uncertainty for investors.

We have discussed the most relevant advantages and inconveniences of different CfD options, but we have not analysed how relevant the different problems and challenges are. Additional research quantifying the different described effects (e.g. the relevance of day-ahead and intraday distortions) is required to estimate the order of magnitudes of the issues. Another open question refers to the relevance of mitigating weather risk. Based on additional research, policy makers would have a better foundation to decide whether prevailing challenges can be handled through ‘smarter’ designs or how the challenges need to be addressed differently. In addition, it should be analysed, to which extent the introduction of new risks as e.g. the basis risks are acceptable for investors in order to avoid that these risks emerge as prohibitive for them.

Another remaining issue is the potential interaction of CfDs with other long-term market segments, more precisely PPA and forward markets. CfD design will influence the attractiveness and scope of the PPA market and the forward markets. Also, implications CfD designs on incentives structures for hybrid plants, e.g. those that produce both electricity and hydrogen, as well as plants with other types of ‘self-consumption’, need to be further investigated. Many issues and secondary policy objectives can often be solved either within CfD design or outside of it, e.g. through more general market rules or through auction design specifications. Also here, further investigations are necessary for improved guidance on how to strike an adequate balance in placing policy solutions.

We expect that (as is the case with other RE support schemes), the answers to many CfD design questions will be highly context-specific. Trade-offs and evaluations for different CfD design choices must take into account not only the physical characteristics of an electricity system as well as the prevailing market characteristics, but also political factors, such as existing support schemes and decision-making principles. Countries will have different counterfactuals that potential CfDs need to be compared to. Speed of implementation and tolerance for failure and subsequent adjustments of the schemes are also typically factors that policy makers factor in when choosing a support scheme. For many, it may be more relevant to be cautious about introducing a substantial system change for RE support than to eliminate remaining inefficiencies in bidding behaviour, depending on how urgent and substantial RE build-out targets are.

The bottom line is that any CfD implementation will face numerous design choices, which all come with their own challenges and trade-offs. We hope that this report has provided relevant information and arguments for an informed European debate on Contracts-for-Difference for RE support.

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# Appendix: Implementation examples of CfDs in Europe

## A.1 Denmark

In Denmark CfDs have so far only been used for offshore wind installations.[5] Completed rounds include Horns Rev 2 (209 MW) and Rødsand 2 (207 MW) in 2005, Anholt (400 MW) 2010, Horns Rev 3 (390 MW) in 2015, Nearshore areas (350 MW) and Kriegers Flak (600 MW) in 2016, and Thor (800 – 1000 MW) in 2021 (González & Kitzing, 2019). None of the strike prices were indexed to inflation. Up until and including Kriegers Flak, all contracts included hourly reference prices and a maximum duration of 20 years that is paired with a total cap on supported production. Pausing payouts during times of negative prices was introduced with the Anholt tender in 2010 (Kitzing & Wendring, 2015; SA.45974, 2017).

Yet, the CfD design for Thor included four main changes. While all previous contracts include hourly reference prices, the one for Thor employs the simple annual average of hourly prices of the previous year. Thus, fixing the price premium for an entire calendar year. Secondly, during years in which the RE operator is obliged to pay the counterparty (i.e., the reference price exceeds the strike price), the requirement is suspended if the necessary payment exceeds the spot price (i.e., limited clawback at low prices). It was opted to still restrict the duration of the contract to 20 years (to avoid aid payments after depreciation). For Thor this was supplemented with a spending instead of a production cap. The CfD is paused if total payments from state to concession owner exceed DKK 6.5 bn., or DKK 2.8 bn in the opposite direction (both valued at 2018 prices). The contract is reactivated if payments in the opposite direction of the respective cap are made. Lastly, payments for Thor are no longer netted but settled monthly with payment streams in both ways (Danish Energy Agency, 2020).

## A.2 France

French CfDs started in 2016 with administratively allocated CfDs for onshore wind (SA.46655, 2016). In 2017, this was replaced by a regulation which restricted this form of support to small installations (no more than 6 turbines with 3 MW each) and established auctions for remaining projects. The administrative price was set at the weighted average long-term production costs. Contracts were awarded for 20 years but, in this version, included an annual production ceiling beyond which the premium is reduced. Total payments were set to be calculated on a yearly basis as a sum across months. Monthly amounts are determined by multiplying the respective (net) production volume with the difference of the strike price (plus a fixed management premium)[6] and the monthly volume-weighted average electricity market price during hours of non-negative prices. This difference is then reduced by proceedings from the capacity remuneration mechanism (SA.47205, 2017). Strike prices are generally indexed in proportion to French labour and producer price indices.

Another particularity of French CfDs is that support pauses during negative prices unless the installation has successfully stopped production during (at least) 20 hours of negative prices. In this case, the installation receives a reduced premium.[7] In later CfD implementations, this remained to be the case for onshore wind. However, for PV, offshore wind, and biomass, it was opted to set this threshold to 15, 40, and 70 hours, respectively.

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[5] Please note that there has been a technology neutral tender round for CfDs in 2021, but no bids were received (Danish Energy Agency, 2021).

[6] This was excluded in later specifications.

[7] Outside the Covid crisis, these thresholds have not been reached to date (SA.100269, 2023).

In 2017, a scheme dedicated to biomass tenders was introduced. It amended the standard calculation of the difference payment by premia and penalties that depend on different commitments. These include a premium for local capital, usage of livestock manure, and usage of waste heat (SA.46698, 2018). In the same year, several tender rounds for PV and onshore CfDs reached state aid approval. They applied the same CfD design as previous rounds, with the difference that only negative prices between 8 a.m. and 8 p.m. (i.e., the peak spot price period) count for the calculation of the premium for negative prices (SA.46552, 2017; SA.47753, 2017; SA.48066, 2017; SA.48238, 2017).

In 2018, a CfD for offshore wind in Dunkirk was introduced. It generally aligned with previous designs but additionally indexed the strike price on the copper and steel price indices. If concrete was used for the fundament, it also included an index for public work. Yet, indexing is only applied after the construction phase to incentivise early completion of construction. The reference price was chosen to be the monthly average electricity price, weighted hourly by the total wind production volume in France (SA.51061, 2018). The last multi-technology (i.e., PV, onshore wind, and hydro) regulation was introduced in 2021. It replaced existing measures and foresees a total annual volume of technology-specific as well as technology-neutral tenders of more than 5 GW until 2026 (SA.50272, 2021).

In 2023, a 1 GW offshore wind project off the coast of Normandy was tendered with as CfD (Tedeschi & Thollet, 2023). Again, most design elements were taken over from the previous round. Yet, the possible remuneration during negative prices was reduced from 100 % (as for Dunkirk) to 70 % of the strike price and the monthly averaging for the reference price was set to be weighted on the production of the actual facility (SA.62218, 2021).

Also in 2023, the first CfD for floating offshore wind reached state aid approval. Apart from only indexing the strike price until 24 months after contract award and applying hourly weighting that only takes the total offshore wind production in specific areas into account for the monthly averages of the electricity price, it aligns with previously tendered CfDs and will cover between 230 and 270 MW. Importantly, it keeps the rule from previous CfDs that enables early termination of the contract after payment of discounted amounts received and paid from the producer to the state (SA.100269, 2023).

### A.3 Greece

CfDs for RE support have first been introduced in Greece in 2016, as part of a scheme that was meant to auction off more than 4.3 GW worth of CfDs between 2016 and 2025. When the scheme was introduced, the regulation also allowed support based on administratively set strike prices. However, already in 2016 trial tenders for PV were conducted. After, with some exemptions, non-auctioned RE support was outlawed from 2017, all following years saw several technology specific as well as some joint PV and onshore wind auctions for CfDs (Anatolitis & Jimeno, 2021; Maroulis, 2019).

Building on this scheme, another one was introduced in 2021. Until 2025, it is expected to auction another 4.2 GW of installed capacity (EU Commission, 2021). In terms of the CfD design, there have been no substantial changes over time. It was decided to fix the duration of contracts to 20 years and employ a monthly reference price with technology specific weighting. Also, no support was paid for periods in which electricity prices were zero or lower for more than two consecutive hours. Across all CfDs, it was opted to allocate the risk of general economic developments to the power assets by not inflation-adjusting the strike price (SA.44666, 2016; SA.60064, 2021).

In 2022, Greece also obtained state aid approval to support electricity storage with CfDs alongside investment grants. Support purely based on investment grants was deemed to be insufficient to ensure bankability of projects, given the reliance on uncertain market revenues. CfDs are set to last for 10 years and involve annual settlement between the yearly revenues that were bid and the ones that were generated. Thus, installation's bids are expressed as EUR/MW/Year. Overcompensation is avoided through ex-ante and ex-post market revenue benchmarks (SA.64736, 2022).

By the time of writing this paper, more than 400 MW have been awarded CfDs under this scheme (Regulatory Authority for Energy, 2023). CfDs will continue to play a crucial role in Greek renewable energy support. While details are still under negotiations, the Offshore Wind Law includes a target of 2 GW of floating offshore wind installations by 2030 (Renewables Consulting Group, 2022).

## A.4 Hungary

CfD support in Hungary started with the introduction of the METÁR scheme, which will run from 2017 to 2026 (Szabo John, 2019). Small-scale renewable energy installations below 500 kW (except for wind) were eligible to be awarded CfDs with administratively set strike prices. While strike prices were uniform, the volumes of the contracts were technology specific with durations between 5 to 25 years and capped annual subsidised energy. Larger installations had to take part in auctions. Hence, starting in 2019 there have been technology-neutral tender rounds each year, awarding support for 15 years (Bartek-Lesi et al., 2020). Since then, CfDs with a total volume of more than 800 MW were allocated (own calculations based on (Anatolitis & Jimeno, 2021; Magyar Energetikai és Közmű-szabályozási Hivatal, 2022).

So far, there have been no changes in the specific design choices of the CfDs over time. All tendered contracts stopped support in case of six consecutive hours of negative prices, employed monthly averages with technology-specific weighting as the reference price, and adjusted the strike price along developments of an efficiency-corrected consumer price index (SA.44076, 2017). Further, as part of the "Temporary Crisis and Transition Framework" of the European Commission, a €1.1 billion scheme for the support of electricity storage was approved in 2023. More than 800 MW of new electricity storage installations should be supported and allocation is planned to be facilitated through auctions before the end of 2024. Chosen projects will receive investment grants during construction followed by CfDs with annual settlement during the first 10 years of operation (EU Commission, 2023b).

## A.5 Ireland

The first CfDs in Ireland were auctioned to renewable energy assets as part of RESS 1 (Renewable Energy Support Scheme) in 2020 (EirGrid, 2020b). The next auction round took place in 2022, labelled RESS 2. Both programs employed the same CfD design and awarded more than 1.2 GW and 1.9 GW, respectively (EirGrid, 2020a, 2022). Contracts are settled annually, take capacity revenues into account, and allocate price risk to the public by using hourly reference prices for non-dispatchable technologies. Dispatchable technologies like biomass were assigned to more risk through annual averaging. For both kinds of technologies, general economic risk is carried by renewable assets as the strike price is fixed for the contract's duration, which was set at 15 years.

A particularity of Irish CfDs is that they formally grant the difference payments to a retail supplier that enters a PPA with the beneficiary, making PPAs a mandatory prerequisite to enter a CfD. Difference payments are calculated by the Regulatory Authority and flow between the

PSO and the supplier of the PPA. While the supplier receives the CfD payments the involved parties have relative freedom in the PPA design as they are still commercially negotiated. Further, Irish CfDs included a so-called “curtailment compensation arrangement” (CCA). It is triggered and stays in place for the remainder of the support if the curtailed production relative to the total potential production (i.e., CS = curtailment / (metered production + curtailment)) is at least 10% for two consecutive years. Afterwards, generators are eligible to a payment which equals the product of total loss-adjusted metered quantity and the strike price, adjusted by a so-called CFactor. This factor is set at (1-0.1)/(1-CS)-1 if positive and zero otherwise. Thus, curtailment that exceeds 10% of total potential production is remunerated at the strike price. Importantly, unless the generation reduction is concurrent with the TSOs’ curtailment definition,[8] compensation does not apply to generation reduction which the generator is required to implement. This includes reductions as a response to network constraints, transmission outages, and negative prices (GoI, 2020, 2021).

In 2023, the offshore wind specific ORESS 1 scheme was concluded. The duration was set at 20 years and reference prices remained hourly. Until approximately the commissioning date, strike prices are indexed in proportion to the steel index and the European harmonised consumer price index (HCI). Afterwards, indexing only regards the HCI. ORESS 1 also introduced a novel feature which replaced the CCA, namely the “unrealised available energy compensation” (UAEC) (GoI, 2022). The UAEC is supposed to de-risk projects by supporting availability rather than actual energy produced. At the strike price, it remunerates availability that has not been converted to generation due to curtailment or oversupply. To preserve locational signals, this disregards availability that is curbed due to transmission constraints. It is possible to exit the contract if notice was given 12 months before and all payments were satisfied.

The UAEC is also adapted by the multi technology RESS 3 scheme, which secured more than 640 MW of PV and onshore wind in 2023 (EirGrid, 2023). Due to large stakeholder support, key design principles have been maintained. Noteworthy updates to the scheme include indexation of the strike price by the harmonised consumer price index and a slight extension of contract durations (GoI, 2023b)

Further, within the next two years the official indicative auction schedule foresees two auctions for offshore and onshore installations respectively, with an indicative auction volume of up to 11,000 GWh per round (GoI, 2023a).

## A.6 Italy

In Italy, CfDs began to be used based on a 2015 regulation that only applied to projects on priority lists for new medium size (smaller than 5 MW). Strike prices were administratively set, proportional to technology specific LCOE. On top of that, projects may have been granted possible payments to compensate for innovative technologies. The reference price was set hourly and, depending on the technology, the duration was 20 to 25 years. This scheme included most common sources of renewable energy, except for solar PV, and aimed at supplying a maximum of 260 MW worth of CfDs (SA.43756, 2016).

The main applications of CfDs came with the FER 1 regulation that took effect in 2019. Excluding offshore wind, it allowed for the allocation of CfDs to renewable technologies through mixed-technology tenders. This, however, was only the case for installations above with a

[8] The official definition states that: “If the Control Centre assumed it had control over every price taking generation unit in tie break on the island of Ireland and the security issue presented could be resolved by reducing the output of any or all of the price taking generation units in tie break then that reduction is deemed a curtailment and logged as such.” (SEM Committee, 2013, p. 2).

capacity above 1 MW. Smaller installations were selected based on environmental as well as economic criteria. The authorities opted for hourly reference prices with monthly two-way settlement, no inflation adjustment of the bid, and a duration between 20 and 30 years that resembles the average lifetime of the respective technology. Also, in line with previous designs, payouts were set to cease after six consecutive hours of negative prices (Gestore dei Servizi Energetici, 2022; SA.53347, 2019). With the aim of procuring about 8 GW, FER 1 so far allocated more than 6.2 GW in 11 auction rounds (Gestore Servici Energetici, 2023). FER 2 is planned to be implemented soon and intends to use CfDs that cover a capacity of 4.5 GW by less mature technologies, including 3.5 GW of floating offshore wind (Ministero dell'Ambiente e della Sicurezza Energetica, 2022).

## A.7 Poland

To reach its 2020 renewable energy target, the Polish government awarded CfDs through multiple auctions a year since 2016. The contracts had a maximum duration of 15 years and, when possible, obligations were netted to avoid actual payments from the generator to the counterparty. Like other schemes, payouts were set to pause after six consecutive hours of negative prices. Noteworthy, payments were determined using reference prices based on volume-weighted average prices per day and a consumer price index adjusted strike price. Thus, most price as well as general economic risk was allocated to the public (Diallo et al., 2019; SA.43697, 2017).

Between 2016 and 2021, the auction scheme awarded the mentioned CfDs mainly to solar PV and onshore wind with total capacity of 6.1 GW and 5.1 GW, respectively. This scheme was prolonged until 2027, leading to an expected additional auctioning of approximately 9 GW (SA.64713, 2021).

Although offshore wind installations were allowed to participate in previous auctions, no projects were awarded due to too high LCOE. Therefore, an offshore wind scheme was brought under way to reach the target of about 5.9 GW and 11 GW in 2030 and 2040, respectively. Due to the infancy of the Polish offshore wind sector, CfDs during the first phase of the scheme are allocated outside auctions (until 2025). Afterwards, CfDs will be allocated through competitive bidding. Apart from the different determination of the strike price, both phases will use the same CfD design with a duration of 25 years (and total support capped at 100,000 full load hours per MW) and no payout at negative prices (SA.55940, 2021). So far, three projects were granted a contract under this regulation, Baltica 2, Baltica 3, and Baltic Power (SA.101842, 2022; SA.103177, 2023).

## A.8 Portugal

Following a 2015 state aid approval, CfDs were allowed to be auctioned to most common renewable energy technologies between 2015 and 2016 (SA.41694, 2016). However, no auction initiative was launched (Jimeno, 2019). The first auction round for CfDs took place in 2019, under a new regulation that only regarded PV. Specific to the Portuguese scheme, producers were allowed to submit bids for two kinds of frameworks. One in which producers bid on a fixed feed-in premium and one in which the bid implies a guaranteed remuneration (i.e., CfD). The bids are evaluated against one another by comparing their net present value from the government's perspective, with the higher one winning (del Río et al., 2019).

In two rounds during 2019 and 2020, a capacity of 872 MW was awarded CfDs (Anatolitis & Jimeno, 2021). The 2020 auction did not only include single PV installations but also ones that were combined with a storage facility. These were subject to a different kind of CfD.

Installations will receive an auctioned fixed amount per MW of installed capacity for every month throughout the duration of the contract. However, this remuneration is reduced by the (positive) difference between the electricity market price and the marginal cost of a combined cycle natural gas power plant (multiplied by 90% of the hourly production potential). Thus, a fixed payment is essentially reduced by a sliding feed-in premium. Importantly, the remuneration can also turn negative, implying a payment from the contractor to the system operator (Direção-Geral de Energia e Geologia (DGEG), 2020a). The volume of these contracts amounted to an additional 483 MW (DGEG, 2020b).

In 2022, the world's first floating PV installation was auctioned with a capacity of more than 100 MW (DGEG, 2022). Throughout those years, the awarded CfDs were set at a duration of 15 years and no payout at negative prices. The contracts further specified monthly settlement of differences with hourly reference prices (DGEG, 2021). Strike prices were generally not meant to be adjusted for inflation. However, as a response to inflationary developments, a presidential decree enacted strike prices to be adjusted by the consumer price index (excluding housing) between auction award and commissioning (Presidência do Conselho de Ministros, 2022).

Currently, the first tenders for 2 GW of floating offshore wind are in the preparatory phase (Goncalves, 2023). Thus, more CfD-based support can be expected in the coming years.

## A.9 Spain

CfDs were introduced in Spain as part of a 2020 regulation that was supposed to curb uncertainty to promote the financing of RE. This marked the government's turn from investment to generation support (del Río & Menzies, 2021). Since 2021, four auction rounds allocated CfDs with a total volume of about 6.4 GW and a duration of 12 to 20 years, depending on the technology (own calculations based on (Ministerio para la Transición Ecológica y el Reto Demográfico (MTERD), 2021b, 2021a, 2022a, 2022b). Payments are paused during times of zero or lower hourly reference prices and it was abstained from inflation-adjusting the strike price.

A unique feature of the Spanish CfDs is the way the remuneration is determined. Despite the hourly reference price, the award price in the auction does not imply a guaranteed level of revenue for the generator. This is because a measure of "price received" is used to determine difference payments. The price received (PR) depends on the auction price (AP) as well as the day-ahead market price (DAMP). It is defined as $PR = AP + AF * (DAMP - AP)$, where AF denotes an adjustment factor. The AF can be seen as the share of energy that is remunerated at market price. It is set at 5% and 25% for non-dispatchable and dispatchable installations, respectively.[9] Importantly, if PR is greater than the applicable market price (MP) (i.e., PR>MP), the generator is receiving PR-MP. In case of the opposite (i.e., PR<MP), the generator is obliged to pay MP-RP. This is meant to encourage increased production during times of high market prices so that price hikes are dampened.

Another particularity of the Spanish program is that the applicable market price can be either the day-ahead or the intraday price, depending on which market the unit of electricity was sold to. Yet, to avoid arbitrage, PR employs the day-ahead price in both cases (MTERD, 2020a). Further, to ensure that the economic benefits from this program reach consumers, the Spanish scheme explicitly forbids bilateral agreements such PPAs alongside an active CfD. Also,

[9] The adjustment factor for dispatchable generators may also apply to intermittent RE like onshore wind and solar PV if they are combined with storage for at least two hours (del Río & Menzies, 2021).

contracted generators are subject to a minimum requirement for energy to be delivered after which they may terminate the contract without penalty. Contracted installations are further subject to minimum and maximum annual full-load hours (MTERD, 2020b).

## A.10 United Kingdom

CfDs were first introduced in the UK as part of the 2013 electricity market reform. To prevent delays of upcoming projects, first CfDs were allocated outside of auctions as part of a scheme called Final Investment Decision enabling for Renewables (FIDeR) (National Audit Office, 2014). Shortly afterwards, the first auction round (AR1) was conducted (2014-2015), followed by AR2 (2017), AR3 (2019), AR4 (2021), and AR5 (2023).

Common features of the contracts include a maximum duration of 15 years, indexation of the strike price, and two-way monthly settlement. Further, intermittent producers (e.g., PV and wind) are provided with contracts that include hourly reference prices which are defined as the weighted average settlement prices of N2EX and EPEX. For baseload technologies, such as biomass and nuclear, the reference price is set semi-annually at the level of the forward six-monthly season baseload contract (Department for Business Energy & Industrial Strategy (DBEIS), 2014, 2017, 2019, 2021, 2023a).

Another particularity of CfDs in the UK is that they are not necessarily activated at the time of the installation's commissioning. Yet, the contracts define a "target commissioning window" in which a start date notice needs to be given. Afterwards the so-called "longstop period" begins in which the CfD can still be activated, but its duration will be reduced by the time between closure of the target commissioning window and start date notice. Beyond this period, CfD terms are breached which would lead to termination of the contract (Low Carbon Contracts Company, 2019). Thereby, generators can choose to operate on a merchant basis before activation of the CfD. Yet, since AR5 this possibility is limited. If the installation exceeds a certain output level, the LCCC can issue a so-called unilateral commercial operations notice (UCON) which would activate the CfD within 10 business days (DBEIS, 2023a).

It is also noteworthy that, while AR1, AR4, and AR5 included established as well as emerging technologies AR2 and AR3 excluded the former. Also, with AR2 a rule was introduced to the contract design that stops payments if negative prices occur for at least six consecutive hours. Until this threshold is reached, payouts are capped at the level of the strike price. This was tightened in the regulation for AR4, which stops payouts at negative prices immediately.

The first three auction rounds awarded 12.9 GW to offshore wind, 1 GW to onshore wind, and 72 MW to utility-scale PV (Soroush et al., 2022). While AR4 awarded another 11 GW, including 8.5 GW for wind energy projects (most of it for offshore wind), AR5 included only 3.6 GW and none for offshore wind projects (DESNZ, 2023; WindEurope, 2022).

More CfDs are to be allocated in years to come. The consultation for AR6 (to be auctioned in 2024) closed in the beginning of 2023. Among other things, the government concluded that the current level of market exposure for RE generators shall be maintained (DBEIS, 2023b).

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